DIRECT TESTIMONY AND EXHIBITS

OF

BRIAN HORII

ON BEHALF OF

THE SOUTH CAROLINA OFFICE OF REGULATORY STAFF

DOCKET NOS. 2021-89-E AND 2021-90-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS, AND OCCUPATION.

A. My name is Brian Horii. My business address is 44 Montgomery Street, San Francisco, California 94104. I am a Senior Partner with Energy and Environmental Economics, Inc. ("E3"). Founded in 1989, E3 is an energy consulting firm with expertise in helping utilities, regulators, policy makers, developers, and investors make the best strategic decisions possible as they implement new public policies, respond to technological advances, and address customers' shifting expectations.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have over 30 years of experience in the energy industry. My areas of expertise include avoided costs, utility ratemaking, cost-effectiveness evaluations, transmission and distribution planning, and distributed energy resources. Prior to joining E3 as a partner in 1993, I was a researcher in Pacific Gas and Electric Company's ("PG&E") Research & Development department and was a supervisor of electric rate design and revenue allocation. I have testified before commissions in California, British Columbia, and Vermont, and have prepared testimonies and avoided cost studies for utilities in New York, New Jersey, Texas, Missouri, Wisconsin, Indiana, Alaska, Canada, and China.

I received both a Bachelor of Science and Master of Science degree in Civil Engineering and Resource Planning from Stanford University. My full curricula vita is provided as Exhibit BKH-1. My prior work experience in this subject matter includes the following:

- Developed the methodology for calculating avoided costs used by the California Public Utilities Commission for evaluation of Distributed Energy Resources ("DER") since 2004;
- Developed the methodology for calculating avoided costs used by the California Energy Commission for evaluation of building energy programs;
- Authored avoided cost studies for BC Hydro, Wisconsin Electric Power Company, and PSI Energy;
- Provided review of, and corrections to, PG&E avoided cost models used in their general electric rate case;
- Developed the integrated planning model used by Consolidated Edison, Inc. and Orange and Rockland Utilities, Inc. to determine least cost DER supply plans for their network systems;
- Developed the hourly generation dispatch model used by El Paso Electric Company to evaluate the marginal cost impacts of their off-system sales and purchases;
- Produced publicly vetted tools used in California for the evaluation of energy efficiency programs, distributed generation, demand response, and storage programs;

- Analyzed the cost impacts of electricity generation market restructuring in Alaska, Canada, and China; and
- Developed the "Public Tool" used by California stakeholders to evaluate Net Energy Metering program revisions in California.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA ("COMMISSION")?

A. Yes, I have previously testified before this Commission on numerous occasions on behalf of the South Carolina Office of Regulatory Staff ("ORS"). I testified on behalf of ORS regarding Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") (collectively, the "Companies" and, individually, a "Company") avoided cost methodologies and regarding other topics in Docket Nos. 2019-185-E and 2019-186-E.

Q. WHY WERE YOU RETAINED BY ORS IN THIS PROCEEDING?

A. ORS retained E3 to conduct analyses, review, and develop recommendations regarding the Companies':

1) Standard offers;
2) Avoided cost methodologies;
3) Form power purchase agreements ("PPA");
4) Commitment to sell forms;
5) Consistency of the avoided cost methodology with the Public Utility Regulatory Policies Act of 1978 ("PURPA") requirements; and
6) The reasonableness of the avoided energy and capacity cost rates requested by the Companies.

Q. WHAT GUIDING PRINCIPLES DID YOU APPLY IN YOUR REVIEW OF THE COMPANIES' FILINGS IN THIS DOCKET?

A. My review and resulting recommendations are based on standard industry principles for the establishment of avoided costs for electrical utilities. These principles are clearly represented in Section 58-41-20 (A) of Act 62, which mandates that the Commission's decisions in these proceedings "… shall be just and reasonable to the ratepayers of the electrical utility, in the public interest, consistent with PURPA and the Federal Energy Regulatory Commission's [("FERC")] implementing regulations and orders, and nondiscriminatory to small power producers; and shall strive to reduce the risk placed on the using and consuming public."

Q. IN YOUR OPINION, WERE THE COMPANIES' FILINGS IN THESE DOCKETS REASONABLY TRANSPARENT FOR YOUR INDEPENDENT REVIEW AND ANALYSIS?

A. Yes. The Companies provided information in their filings and data responses that allowed me to assess the reasonableness of their proposals, to make important improvements to their assumptions, and to flow those changes through their models so that I could easily derive my recommended tariffs and PPA rates.

Q. BRIEFLY DESCRIBE THE REQUIREMENTS OF PURPA AND HOW THE REQUIREMENTS RELATE TO DEC'S PROPOSED PURCHASED POWER SCHEDULES ("SCHEDULE PP (SC)" AND "SCHEDULE PP-LQF (SC)") AND DEP'S PROPOSED PURCHASED POWER SCHEDULES ("SCHEDULE PP-6" AND "SCHEDULE PPL-4") (COLLECTIVELY, THE "STANDARD OFFERS").

A. In 1978, as part of the National Energy Act, Congress passed PURPA. The policy was designed, among other things, to encourage conservation of electric energy, increase efficiency in use of facilities and resources by utilities, and produce more equitable retail rates for electric consumers.

To help accomplish these goals, PURPA established a special class of generating facilities called Qualifying Facilities ("QFs"). QFs receive special rate and regulatory treatments, including the ability to sell energy and capacity to electric utilities. In addition, all electric utilities, regardless of ownership structure, must purchase energy and/or capacity from, interconnect to, and sell back-up power to a QF. This obligation is waived if the QF has non-discriminatory access to competitive wholesale energy and long-term capacity markets.

In the DEC and DEP service territories, generators that are designated as QFs and have capacity less than or equal to two megawatts ("MW") are compensated under the proposed Standard Offers.

Q. COMPANY WITNESS SNIDER STATES ON PAGE 10 OF HIS DIRECT TESTIMONY THAT THE COMPANIES USE THE "PEAKER METHOD" TO FORECAST AVOIDED ENERGY AND CAPACITY COSTS. DOES ORS CONSIDER THE PEAKER METHOD TO BE A VALID METHOD FOR DETERMINING AVOIDED ENERGY AND CAPACITY COSTS?

A. Yes. This is one of the generally accepted methods for calculating PURPA avoided energy and capacity costs and is used throughout the United States. The Peaker Method uses the installed fixed capacity cost of a simple-cycle combustion turbine ("CT") plus the marginal energy costs of running the system as a proxy for the marginal capacity and energy costs that a utility avoids by purchasing power from a QF. The Commission approved the use of the Peaker Method in Order No. 2019-881(A).

AVOIDED ENERGY COSTS

Q. DOES THE AVOIDED ENERGY COST CALCULATION METHOD USED BY THE COMPANIES CONFORM WITH THE METHOD APPROVED BY THE COMMISSION IN ORDER NO. 2019-881(A)?

A. Yes. The Companies have undertaken a production cost simulation that identifies the dispatch of the Companies' fleet of generating resources needed to meet the load in each hour over the ten-year avoided cost period. In conducting the avoided energy cost calculation, the Companies simulate a Base Case, consistent with its most recent Integrated Resource Plan ("IRP"), and separately perform an alternative simulation that assumes a hypothetical 100 MW of independent generation in every hour of the ten-year period. The simulation also determines the marginal units that are displaced with the 100 MW unit. The difference between the generation costs in that scenario relative to the Base Case over the ten-year study period determines the marginal hourly avoided energy costs, which are used to value the generation of the QF. The Companies' avoided costs include not only reduced fuel, but also lower environmental allowance costs and variable operating expenses. The Companies' method to estimate avoided energy costs is standard practice within the Peaker Method, which compares total production costs under a Base Case with total production costs in scenarios that assume a given block of QF supply.

Q. PLEASE DESCRIBE THE UPDATES PROPOSED BY THE COMPANIES TO THE AVOIDED ENERGY COSTS COMPARED TO THOSE APPROVED BY THE COMMISSION IN ORDER NO. 2019-881(A).

A. My review of the Companies' current and prior testimony and work papers indicates no methodological differences regarding those approved by the Commission in Order No. 2019-881(A). The most significant driver of the change in avoided energy cost is the updated fuel price forecasts. Other variables of impact include differences between the IRPs filed by the Companies in 2019 and 2020, which include differences in purchased power amounts, changes in projected generation capacities of various utility-owned generation technologies, and reduced growth in long-term annual sales forecasts.

Q. PLEASE DESCRIBE THE UPDATES PROPOSED BY THE COMPANIES TO THE TIME OF USE ("TOU") PERIODS.

A. Similar to the 2019 Avoided Cost proceeding, the Companies propose to divide the year into three seasons (Summer: June - September; Winter: December – February; and Shoulder for all other months) with three TOU periods for each season. The TOU periods differ for DEC and DEP as a reflection of the differing hourly load profile of each Company, net of solar generation, and the corresponding hourly marginal costs. The Companies also identify the hours in which the marginal costs (and net loads) are above the seasonal average. These hours represent either on-peak or premium peak hours, with those above the 85th-percentile level considered premium peak hours.

In addition to load and generation cost updates, the Companies propose to update the Standard Offer avoided energy rate designs by modifying the hourly differentiation for DEC. Specifically, the Company proposes to remove the weekday summer on-peak period (7 a.m. to noon) resulting in 10 TOU periods, which is one less than the 11 TOU periods that were approved by the Commission in Order No. 2019-881(A). Based on my review of the Companies' Witness Snider Direct Testimony DEC/DEP Exhibit 2, I confirmed that the change in the DEC TOU periods reasonably reflects the updated energy cost profile in DEC's service territory. Under the ten-year projection of levelized energy costs, the summer morning hours show relatively lower marginal costs of service, ranging from $22/MWh to $24/MWh, as compared to the projected marginal costs in the Companies' 2019 Avoided Cost filings. The costs in these hours now are very similar to the costs of the overnight summer hours from midnight to 7 a.m., which range from $20/MWh to $24/MWh. Thus, these hourly costs are appropriately categorized as off-peak hours based on the 10-year projection.

The Companies continue to propose the same nine TOU periods for DEP that were approved in Order No. 2019-881(A). I find this to be reasonable based on the hourly variation contained in Exhibit 8 of the DEP Application.

Q. DOES ORS RECOMMEND ANY CHANGES TO THE COMPANIES' AVOIDED ENERGY COST CALCULATIONS OR RESULTING RATES APPLICABLE TO THE STANDARD OFFER TARIFFS?

A. No. Based on my review, the avoided energy costs reflected by the Companies in the Standard Offer tariffs are a reasonable result of the Companies' calculations. The calculation methodology is consistent with PURPA and the Commission's prior approval of the methodology in Order No. 2019-881(A). In addition, the Companies' proposal to merge the hours from 7 a.m. to noon with the overnight hours into a single off-peak period is reasonable based on the marginal energy cost projections.

AVOIDED CAPACITY COSTS

Q. PLEASE DESCRIBE THE METHODOLOGY THE COMPANIES USED TO CALCULATE PROPOSED AVOIDED CAPACITY COSTS.

A. The basic steps that the Companies used are as follows:

1) Estimate the annual cost of a new simple-cycle CT as the proxy for the cost of generation capacity. The annual cost consists of return on and of capital, income taxes, property taxes, insurance, working capital, a general plant loading factor, losses, and a performance adjustment factor.

2) For each Company, estimate ten years of annual capacity costs. For years prior to when generation capacity is needed by the Company, insert a zero annual capacity cost. For the year that the Company requires generation capacity and all subsequent years, insert the annual cost from Step 1. The

first year of capacity need is determined by the Companies' 2020 IRP, which for DEC is 2022 and for DEP is 2026.

3) Calculate the levelized cost of capacity for one, five, and ten-year delivery periods starting in 2022.

4) Allocate the levelized cost of capacity to the summer and winter periods based on the DEC and DEP Loss of Load Expectation ("LOLE") results from the 2018 Value of Solar Capacity ("VoSC") studies. The LOLE represents the relative probability of a generation outage over each hour of the year based on variations in customer demand and generation availability.

5) Allocate the seasonal capacity values to hours of the day based on the Companies' LOLE studies from the 2020 IRP. This allocation converts the levelized capacity costs from \$/kW-year values to \$/kWh values, which are appropriate to include in the calculation of the TOU avoided costs contained in the Standard Offer and Large QF Tariffs and PPAs.

Q. IS THE METHOD USED BY THE COMPANIES TO CALCULATE AVOIDED CAPACITY COSTS CONSISTENT WITH PURPA AND THE METHODOLOGY APPROVED BY THE COMMISSION IN ORDER NO. 2019-881(A)?

A. Yes. This method is one of the generally accepted methods for calculating PURPA avoided capacity costs and is used throughout the United States.

Q. DOES ORS FIND THAT THE COMPANIES' ESTIMATES OF GENERATION CAPACITY COST ARE REASONABLE?

A. Yes. The DEC and DEP estimates of generation capacity costs follow the methodology adopted by the Commission in Order No. 2019-881(A). Where inputs into the calculation have been updated by the Companies, I also find the updates to be reasonable.

Q. DOES ORS AGREE WITH THE COMPANIES' ALLOCATIONS OF CAPACITY COSTS TO SUMMER AND WINTER SEASONS?

A. The allocation of zero capacity cost to the summer season for DEP is reasonable. However, ORS asserts that DEC's proposed 11% summer season allocation should be adjusted down to 5%. Based on my review and analysis, the 5% summer allocation better reflects DEC's need for capacity in the summer as evidenced by the Company's most recent study of capacity need.

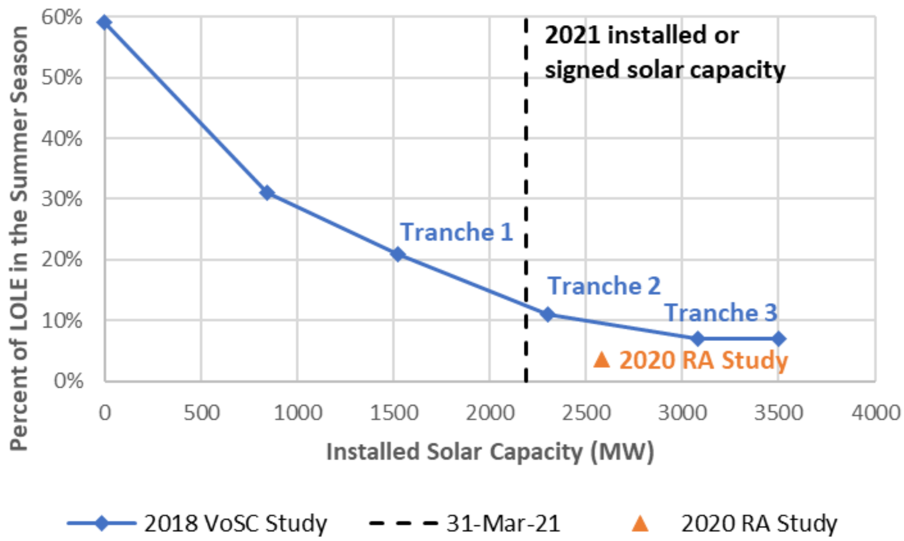
Q. PLEASE EXPLAIN WHY ORS RECOMMENDS A MODIFICATION TO REDUCE THE DEC PROPOSED SUMMER ALLOCATION OF GENERATION CAPACITY COSTS.

A. There are two studies that can be used to determine the allocation of generation capacity to the summer season. One is DEC's 2018 VoSC study,[1] and the other is DEC's 2020 Resource Adequacy ("RA") study provided as part of DEC's 2020 IRP proceeding in Docket No. 2019-224-E, a copy of which is attached as Exhibit BKH-3.

[1] Summary results are shown in Exhibit BKH-2, which consists of DEC's response to ORS AIR 1-4.

Figure 1 below shows the Summer LOLE totals estimated by DEC in the VoSC and RA studies. The VoSC evaluated numerous solar installation scenarios, and those results are shown as the blue squares in Figure 1. As shown by the orange triangle in Figure 1, the DEC 2020 RA study estimates that 3.6% of the loss of load risk would occur in the summer based on 2,579 MW of installed solar.[2] The dashed vertical line in Figure 1 reflects the amount of solar capacity installed or under contract as of March 31, 2021.

Figure 1
2018 VoSC Summer LOLE



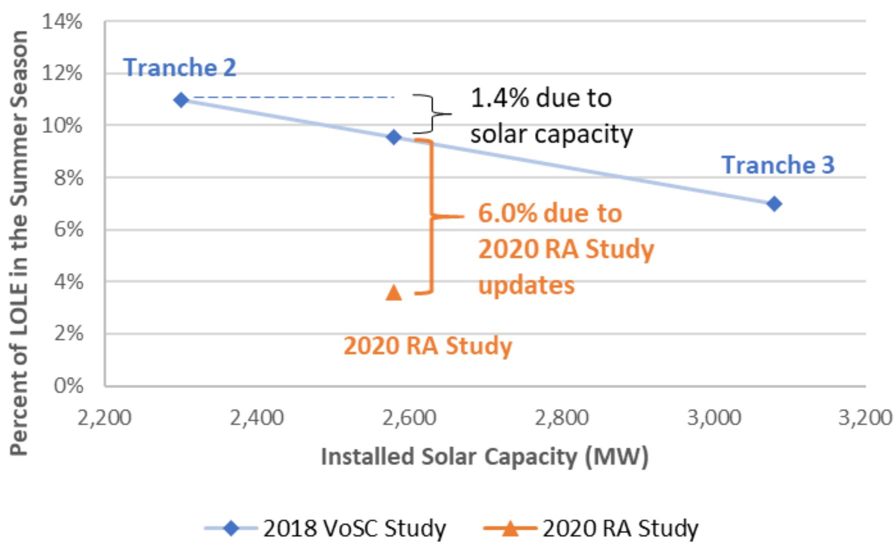
DEC proposes to allocate 11% of the generation capacity cost to the summer season based on the summer LOLE from the 2018 VoSC study's Tranche 2 scenario. As shown in Exhibit BKH-2, the Company used the VoSC study's Tranche 2 because the scenario modeled a level of installed solar capacity (2,300 MW) that more closely matches the current amount of installed solar capacity (2,191 MW) than the 2020 RA study's

[2] Exhibit BKH-3, p. 68.

assumption (2,579 MW).[3] Although it is appropriate to have the summer LOLE reflect the amount of current installed solar capacity, DEC's use of the 2018 VoSC study ignores the modeling improvements that the Company made in the 2020 RA study.

Figure 2 below is a close-up of the LOLE focused on the differential between Tranches 2 and 3. Figure 2 shows that the amount of installed solar capacity accounts for about a 1.4% difference in summer LOLE.[4] However, the majority of the difference (approximately 6.0% of the total 7.4% difference) is driven by other study assumption improvements and updates reflected in the 2020 RA study.

Figure 2
Differences between DEC 2018 VoSC and 2020 RA Studies on Summer LOLE



[3] Solar installed capacity values from DEC Response to ORS AIR 1-4.

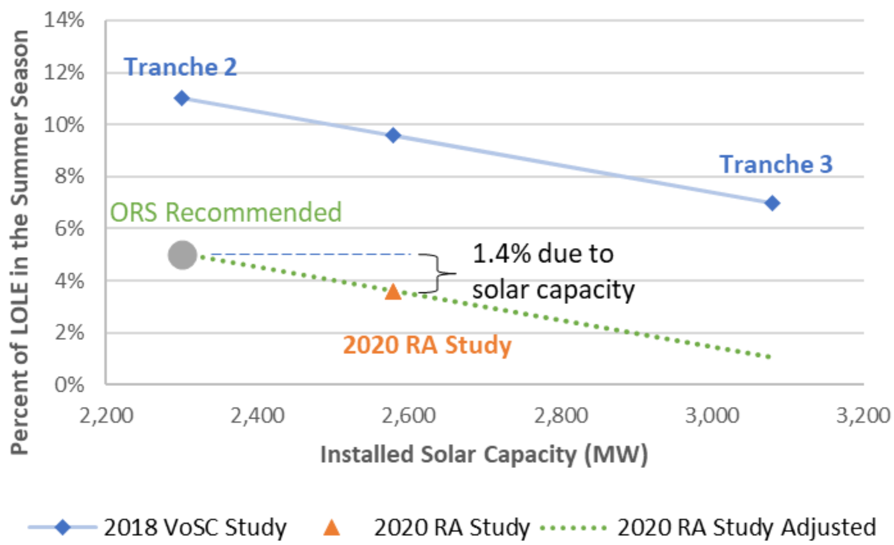
[4] The 2018 VOSC value at 2,579 MW is calculated using a linear interpolation between Tranche 2 and Tranche 3 results.

According to the DEC response to ORS AIR 2-5, a copy of which is attached as Exhibit BKH-4, the 2020 RA study made improvements to customer peak load estimation as well as updates to resource characteristics, generator outage rates, hourly solar profiles, and information about neighboring resources, loads, and transmission capability.

Q. WHAT IS YOUR RECOMMENDED SUMMER LOLE FOR DEC?

A. I recommend that, instead of using the 2018 VoSC study Tranche 2 summer LOLE, the summer allocation should be calculated as the sum of the 3.6% summer LOLE from the 2020 RA study plus 1.4% to reflect that installed solar capacity in 2022 is expected to be lower than the installed solar capacity assumed in the 2020 RA study. This would result in a total summer LOLE of 5% (3.6% + 1.4%). As illustrated in Figure 3 below, the green dashed line shows the 2020 RA Study result adjusted to change with varying levels of installed solar capacity based on the relationship between summer LOLE and solar capacity from the 2018 VoSC study. The LOLE changes, with differences in capacity, are based on a linear interpolation of summer LOLE between Tranches 2 and 3 of the 2018 VoSC study. My recommended value for the DEC Summer LOLE, shown as the circle in Figure 3, is the 2020 RA study result increased by 1.4% to reflect a Tranche 2 level of installed solar capacity.

Figure 3
ORS Recommended DEC Summer LOLE



Q. WHAT ARE THE GENERATION SEASONAL CREDITS FOR DEC USING ORS'S 5% SUMMER CAPACITY ALLOCATION?

A. ORS's recommended generation capacity seasonal credits are summarized in Table 1 below. The credits were derived using DEC's electronic workpapers for Companies' Witness Snider Direct Testimony DEC Exhibit 1, pages 4-6.[5] ORS updated the seasonal allocations in line 4 of the tables in Companies' Witness Snider Direct Testimony DEC Exhibit 1, pages 4-6 to 5% summer and 95% winter. No other inputs were changed, and the results in Table 1 are derived directly from line 9 of DEC's electronic workpapers for Companies' Witness Snider Direct Testimony DEC Exhibit 1.

[5] The electronic workpaper spreadsheet is DEC_SC_2021-Exhibit2-Confidential.xlsx, provided in response to ORS AIR 1-5.

Table 1
ORS Recommended Generation Capacity Seasonal Credits for DEC

	Distribution		Transmission	
	Summer	Winter	Summer	Winter
Variable Rate (cents/kWh)	0.00	0.00	0.00	0.00
5-Yr Fixed Long-Term Rate (cents/kWh)	0.30	2.37	0.30	2.30
10-Yr Fixed Long-Term Rate (cents/kWh)	0.93	7.21	0.90	7.02

Q. DOES ORS RECOMMEND ANY CHANGES TO THE DEP PROPOSED AVOIDED CAPACITY RATES?

A. No. They are a reasonable result derived from the method approved by the Commission in Order No. 2019-881(A). Based on the level of currently installed solar capacity in the DEP system, the DEP proposed rates reasonably allocate zero capacity cost to the summer period. Therefore, ORS does not recommend changes to adjust the seasonal allocation of capacity costs for DEP.

Q. DOES ORS RECOMMEND THAT THE AVOIDED COSTS FOR THE COMPANIES INCLUDE CAPACITY AVOIDED COSTS FOR TRANSMISSION AND DISTRIBUTION ("T&D")?

A. Not at this time. While ORS does support the inclusion of T&D capacity avoided costs, it should not be included until the Commission issues its final order in Docket No. 2019-182-E. Moreover, if an order were issued prior to completion of the avoided cost dockets, the information presented in this docket or Docket No. 2019-182-E should be verified and vetted to ensure that it provides reliable data on the allocation of T&D capacity costs to TOU periods. In addition, the inclusion of T&D capacity avoided costs should consider the effect of the timing and intermittency of generation resources on T&D capacity need reduction (similar to how effective load carrying capability, or ELCC, is being used for generation capacity avoided costs for solar). Without such verified and vetted data, it would be premature to include T&D capacity avoided costs in the tariffs adopted herein.

Q. BASED ON THE APPLICATION AND TESTIMONY, IT APPEARS DEC AND DEP HAVE NOT UPDATED THE COSTS FOR INTEGRATING RENEWABLE GENERATION. IS IT REASONABLE TO CONTINUE TO USE THE INTEGRATION COSTS FROM 2019 DOCKETS?

A. Yes. As noted on page 15 of the Joint Application of DEC and DEP, the independent technical review of solar integration costs has commenced but is not complete. Therefore, it is appropriate to continue to use the integration cost values adopted in Order No. 2019-881(A).

Q. DOES ORS OBJECT TO THE COMPANIES' PROPOSED CHANGES TO THE WORDING, TERMS, OR CONDITIONS OF THE REVISED STANDARD OFFER TARIFF, STANDARD OFFER PPA, LARGE QF TARIFF, LARGE QF PPA, OR NOTICE OF COMMITMENT FORM?

A. No. The proposed language changes are predominantly "housekeeping" changes such as header and footer changes. I find the other very minimal changes to be reasonable and non-discriminatory to QFs. In short, the documents remain consistent with or contain slight improvements to those approved by the Commission in Order No. 2019-881(A).

Q. PROVIDE A SUMMARY OF ORS'S RECOMMENDATIONS FOR COMMISSION CONSIDERATION IN THIS DOCKET.

A. ORS's recommendations are as follows:

1) DEC and DEP avoided energy cost rates as proposed should be adopted for Standard Offer and PPA contracts.
2) ORS's allocation of capacity costs to seasons should be adopted for DEC to reflect the most up-to-date analysis of DEC generation capacity need.
3) ORS has no objection to the capacity costs for DEP.
4) T&D capacity costs should not be included in the Standard Offer and PPA contracts at this time.
5) The solar integration costs should remain at the values approved by the Commission in Order No. 2019-881(A) at this time.

Q. WILL YOU UPDATE YOUR TESTIMONY BASED ON INFORMATION THAT BECOMES AVAILABLE?

A. Yes. ORS fully reserves the right to revise its recommendations via supplemental testimony should new information not previously provided by the Companies, or other sources, become available.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

Brian Horii

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ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Senior Partner 1993 – Present

Mr. Horii is one of the founding partners of Energy and Environmental Economics, Inc. (E3). He is a lead in the practice areas of Resource Planning; Energy Efficiency and Demand Response; Cost of Service and Rate Design; and acts as a lead in quantitative methods for the firm. Mr. Horii also works in the Energy and Climate Policy, Distributed Energy Resources, and regulatory support practice areas. He has testified and prepared expert testimony for use in regulatory proceedings in California, South Carolina, Texas, Vermont, British Columbia, and Ontario, Canada. He designed and implemented numerous computer models used in regulatory proceedings, litigation, utility planning, utility requests for resource additions, and utility operations. His clients include BC Hydro, California Energy Commission, California Public Utilities Commission, Consolidated Edison, El Paso Electric Company, Hawaiian Electric Company, Hydro Quebec, Minnesota Department of Commerce, NYSERDA, Orange and Rockland, PG&E, Sempra, Southern California Edison, and South Carolina Office of Regulatory Staff.

Resource Planning:

- Authored the Locational Net Benefits Analysis (LNBA) tool used by California IOUs to evaluate the total system and local benefit of distributed energy resources by detailed distribution subareas
- Created the software used by BC Hydro to evaluate individual bids and portfolios tendered in calls for supplying power to Vancouver Island, demand response from large customers, and new clean power generation
- Designed the hourly generation dispatch and spinning reserve model used by El Paso Electric to simulate plant operations and determine value-sharing payments
- Evaluated the sale value of hydroelectric assets in the Western U.S.
- Simulated bilateral trading decisions in an open access market; analyzed market segments for micro generation options under unbundled rate scenarios; forecasted stranded asset risk and recovery for North American utilities; and created unbundled rate forecasts
- Reviewed and revised local area load forecasting methods for PG&E, Puget Sound Energy, and Orange and Rockland Utilities

Energy Efficiency, Demand Response, and Distributed Resources:

- Author of the “E3 Calculator” tool used as the basis for all energy efficiency programs evaluations in California since 2006
- Independent evaluator for the development of locational avoided costs by the Minnesota electric utilities
- Consulted on the development of the NEM 2.0 Calculator for the CPUC Energy Division that was used by stakeholders in the proceeding as the common analytical framework for party positions; also authored the model’s sections on revenue allocation that forecast customer class rate changes over time, subject to changes in class service costs

- Co-author of the avoided cost methodology adopted by the California CPUC for use in distributed energy resource programs since 2005
- Principal consultant for the California Energy Commission's Title 24 building standards to reflect the time and area specific value of energy usage reductions and customer-sited photovoltaics and storage
- Principal investigator for the 1992 EPRI report *Targeting DSM for Transmission and Distribution Benefits: A Case Study of PG&E's Delta District*, one of the first reports to focus on demand-side alternatives to traditional wires expansion projects
- Provided testimony to the CPUC on the demand response cost effectiveness framework on behalf of a thermal energy storage corporation

Cost of Service and Rate Design:

- Designed standard and innovative electric utility rate options for utilities in the U.S., Canada, and the Middle East
- Principal author of the *Full Value Tariff and Retail Rate Choices* report for NYSERDA and the New York Department of Public Staff as part of the New York REV proceeding
- Developed the rate design models used by BC Hydro and the BCUC for rate design proceedings since 2008
- Principal author on marginal costing, ratemaking trends and rate forecasting for the California Energy Commission's investigation into the revision of building performance standards to effect improvements in resource consumption and investment decisions
- Consulted to the New York State Public Service Commission on appropriate marginal cost methodologies (including consideration of environmental and customer value of service) and appropriate cost tests
- Authored testimony for BC Hydro on Bulk Transmission Incremental Costs (1997); principal author of B.C. Hydro's System Incremental Cost Study 1994 Update (With Regional Results Appendix)
- Performed detailed market segmentation study for Ontario Hydro under both embedded and marginal costs
- Testified for the South Carolina Office of Regulatory Staff on SCANA marginal costs
- Taught courses on customer profitability analysis for the Electric Power Research Institute
- Other work has addressed marginal cost-based revenue allocation and rate design; estimating area and time specific marginal costs; incorporating customer outage costs into planning; and designing a comprehensive billing and information management system for a major energy services provider operating in California

Transmission Planning and Pricing:

- Designed a hydroelectric water management and renewable integration model used to evaluate the need for transmission expansion in California's Central Valley
- Developed the quantitative modeling of net benefits to the California grid of SDG&E's Sunrise Powerlink project in support of the CAISO's testimonies in that proceeding
- Testified on behalf of the Vermont Department of Public Service on the need for transmission capacity expansion by VELCO
- Determined the impact of net vs. gross billing for transmission services on transmission congestion in Ontario and the revenue impact for Ontario Power Generation

- Authored numerous Local Integrated Resource Planning studies for North American utilities that examine the cost effectiveness of distributed resource alternatives to traditional transmission and distribution expansions and upgrades
- Developed the cost basis for BC Hydro's wholesale transmission tariffs
- Provided support for numerous utility regulatory filings, including testimony writing and other litigation services

Energy and Climate Policy:

- Author of the E3 "GHG Calculator" tool used by the CPUC and California Energy Commission for evaluating electricity sector greenhouse gas emissions and trade-offs
- Primary architect of long-term planning models evaluating the cost and efficiency of carbon reduction strategies and technologies
- Testified before the British Columbia Public Utilities Commission on electric market restructuring

PACIFIC GAS & ELECTRIC COMPANY San Francisco, CA
Project Manager, Supervisor of Electric Rates 1987-1993

- Managed and provided technical support to PG&E's investigation into the Distributed Utilities (DU) concept; projects included an assessment of the potential for DU devices at PG&E, an analysis of the loading patterns on PG&E's 3000 feeders, and formulation of the modeling issues surrounding the integration of Generation, Transmission, and Distribution planning models
- As PG&E's expert witness on revenue allocation and rate design before the California Public Utilities Commission (CPUC), was instrumental in getting PG&E's area-specific loads and costs adopted by the CPUC and extending their application to cost effectiveness analyses of DSM programs
- Created interactive negotiation analysis programs and forecasted electric rate trends for short-term planning

INDEPENDENT CONSULTING San Francisco, CA
Consultant 1989-1993

- Helped develop methodology for evaluating the cost-effectiveness of decentralized generation systems for relieving local distribution constraints; created a model for determining the least-cost expansion of local transmission and distribution facilities integrated with area-specific DSM incentive programs
- Co-authored *The Delta Report* for PG&E and EPRI, which examined the targeting of DSM measures to defer the expansion of local distribution facilities

Education

Stanford University Palo Alto, CA
M.S., Civil Engineering and Environmental Planning 1987

Stanford University — Palo Alto, CA

B.S., Civil Engineering — 1986

Citizenship

United States

Refereed Papers

1. *Woo, C.K., I. Horowitz, B. Horii, R. Orans, and J. Zarnikau (2012) "Blowing in the wind: Vanishing payoffs of a tolling agreement for natural-gas-fired generation of electricity in Texas," The Energy Journal, 33:1, 207-229.*
2. *Orans, R., C.K. Woo, B. Horii, M. Chait and A. DeBenedictis (2010) "Electricity Pricing for Conservation and Load Shifting," Electricity Journal, 23:3, 7-14.*
3. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*
4. *Woo, C.K., B. Horii, M. Chait and I. Horowitz (2008) "Should a Lower Discount Rate be Used for Evaluating a Tolling Agreement than Used for a Renewable Energy Contract?" Electricity Journal, 21:9, 35-40.*
5. *Woo, C.K., E. Kollman, R. Orans, S. Price and B. Horii (2008) "Now that California Has AMI, What Can the State Do with It?" Energy Policy, 36, 1366-74.*
6. *Baskette, C., B. Horii, E Kollman, and S. Price (2006) "Avoided cost estimation and post reform funding allocation for California's energy efficiency programs," Energy 31, (2006) 1084-1099.*
7. *Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA, 34:1, 70-80.*
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Duke Energy Carolinas, LLC's
and
Duke Energy Progress, LLC's
Response to
SC Office of Regulatory Staff
Data Request No. 1-4

Docket No. 2021-89-E
Docket No. 2021-90-E

Date of Request:	**April 30, 2021**
Date of Response:	**May 12, 2021**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Tom Davis, Principal Planning Analyst, and was provided to the SC Office of Regulatory Staff under my supervision.

Rebecca J. Dulin
Associate General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

1-4 Provide a detailed explanation of the "loss of load risk" calculations behind the updated seasonal capacity cost reallocation from 4% allocation to 11% in the summer for DEC and the 0% summer capacity allocation for DEP, on pages 3 (DEC) and 5 (DEP) of Exhibit 8, to include a detailed explanation of:

(a) whether and how transmission or availability of purchases of capacity outside of DEC or DEP systems have been accounted for in mitigating the loss of load risk approach;

(b) what drives the difference in the winter peak, e.g. starts earlier and ends one hour earlier for DEP compared to winter period for DEC;

(c) if the zero summer loss of load risk is based on normal weather summer, and other details of the approach.

Response:

(a) Consistent with the methodology approved by the Commission in the 2019 avoided cost proceedings, DEC and DEP updated their avoided capacity rate designs to reflect the loss of load risk based on the 2020 Resource Adequacy Studies (RA Studies) conducted by Astrapé Consulting. The 2020 Resource Adequacy Studies were filed with the Commission in Docket No. 2019-224-E and 2019-225-E on September 1, 2020, as Attachment III to the DEC and DEP 2020 IRPs, respectively.

Seasonal Allocation:
For DEC, the loss of load risk table from the 2020 RA Study shows a seasonal allocation of 96% Winter and 4% Summer (reference Exhibit 8 filed with Duke's April 22, 2021 Application, and response to ORS AIR 1-3(c)). However, this allocation is based on the 2,579 MW of solar projected for 2024, which was the study year for the 2020 Resource Adequacy Study. Consistent with the Commission's determination in Order No. 2019-881(A), DEC has developed the seasonal allocation factors based on total connected solar plus solar projects with signed PPAs. As of March 31, 2021, total connected solar projects plus projects with signed PPAs was 2,191 MW. Since the actual level of solar was less than what was assumed in the 2020 RA Study and given that a solar sensitivity was not conducted as part of the 2020 RA Study, Duke used results from the 2018 Solar Capacity Value Study to determine the seasonal weighting. The level of currently

connected solar projects plus projects with signed PPAs closely aligns with Tranche 2 solar results from the 2018 Solar Capacity Value Study which shows a seasonal allocation of 11% Summer and 89% Winter for DEC (see attached Table S4 from the Solar Capacity Value study).

Similarly, for DEP the 2020 RA Study assumed 4,107 MW of solar for study year 2024. As of March 31, 2021, DEP had 3,710 MW of connected solar projects plus projects with signed PPAs. Since the actual level of solar was less than what was assumed in the 2020 RA Study and given that a solar sensitivity was not conducted as part of the 2020 RA Study, Duke used results from the 2018 Solar Capacity Value Study to determine the seasonal weighting. The level of currently connected solar projects plus projects with signed PPAs exceeds Tranche 4 solar from the 2018 Solar Capacity Value Study which shows a seasonal allocation of 100% Winter and 0% Summer.

(a) Transmission and Neighbor Modeling

The 2020 RA studies included the capacity support available through interconnections with neighboring utilities. The study topology is described in Section III.B of the study reports. Importantly, the required reserve margin for DEC to meet the 0.1 LOLE standard is reduced from 22.5% in the Island scenario (which does not include interties) to 16.0% in the Base Case (which includes interties) as a result of interties and capacity support from neighboring utilities. Similarly, the required reserve margin for DEP to meet the 0.1 LOLE standard is reduced from 25.5% in the Island scenario to 19.25% in the Base Case. These results are provided in the Executive Summary and Section V of the study reports.

Based on the physical reliability results of the Island, Base Case, Combined Case, and additional sensitivities for both DEC and DEP, Astrapé recommended and the Companies agreed to continue to maintain a minimum 17% reserve margin for IRP purposes.

(b) The LOLE tables provided in Exhibit 8 to the Companies' 2021 avoided cost filing are based on the 2020 Resource Adequacy Studies and show the loss of load risk in a 12x24 (month by hour) format reflecting the percent of total annual LOLE that occurs by hour for each month. For example, for DEC 32.8% of the total annual LOLE occurs in the month of January in hour ending (HE) 8 AM. Similarly, for DEP 20.0% of the total annual LOLE occurs in the month of January in HE 8 AM.

Loss of load risk is also influenced by the amount of solar capacity on the system since solar contributes greater capacity value during summer afternoon peak demands and very little capacity value during winter peak demands which typically occur in early morning hours before solar is fully online. Thus, LOLE values are affected by the amount of must-take solar generation on each system since load net of solar reflects the net load obligation that the rest of the generation system is required to serve. Since DEP has a higher penetration of solar capacity than DEC, DEP has lower LOLE values than DEC in daylight hours when solar capacity is online (assuming all other LOLE drivers being equal). For example, during mid-morning hours when solar capacity is ramping up, solar capacity dampens LOLE more for DEP than DEC due to the higher penetration of DEP solar. This also results in more of the DEP LOLE being shifted to non-daylight hours. The net effect is a one-hour shift in the winter AM loss of load risk between DEC and DEP and thus a shift in the capacity payment hour definitions.

(c) In order to ensure resource adequacy, a minimum reserve margin is needed to manage unexpected conditions including extreme weather, load growth, and significant forced outages. To understand this risk, a wide distribution of possible scenarios must be simulated at a range of reserve margins. To calculate physical reliability, Astrapé utilized a reliability model called SERVM (Strategic Energy and Risk Valuation Model) to perform thousands of hourly simulations for the 2024 study year at various reserve margin levels. Each of the yearly simulations was developed through a combination of deterministic and stochastic modeling of the uncertainty of weather, economic growth, unit availability, and neighbor assistance.

Loss of load risk is largely influenced by the volatility in load due to extreme weather. To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load, a neural network program was used to develop relationships between weather observations and load. These relationships were then applied to the last thirty-nine years of weather data to develop thirty-nine synthetic load shapes for study year 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation.

Figures 2 and 3 from the 2020 RA Study reports show that winter peak load is significantly more volatile than summer peak load for both Companies. Extreme cold temperatures can cause load to spike from additional electric strip heating; whereas, the highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation. Figures 2 and 3 show that DEC winter load can exceed normal weather winter load by approximately 18% in the most extreme winter weather year while summer load only exceeds normal weather summer load by approximately 6% in the most extreme summer weather year. For DEP, winter load can exceed normal weather winter load by approximately 21% in the most extreme winter weather year while summer load only exceeds normal weather summer load by approximately 7% in the most extreme summer weather year. Please reference Section III.C from the 2020 RA Study reports for further information regarding load modeling.

2018 DEC and DEP Solar Capacity Value Study, at 7:

Table S4. DEC and DEP Seasonal LOLE Percentage

	DEC Incremental Solar MW	DEC Cumulative Solar MW	DEC LOLE Summer %	DEC LOLE Winter %	DEP Incremental Solar MW	DEP Cumulative Solar MW	DEP LOLE Summer %	DEP LOLE Winter %
0 MW Level	-	-	59%	41%	-	-	14.7%	85.3%
Existing Plus Transition MW	840	840	31%	69%	2950	2,950	0.6%	99.4%
Tranche 1	680	1,520	21%	79%	160	3,110	0.5%	99.5%
Tranche 2	780	2,300	11%	89%	180	3,290	0.4%	99.6%
Tranche 3	780	3,080	7%	93%	160	3,450	0.3%	99.7%
Tranche 4	420	3,500	7%	93%	135	3,585	0.3%	99.7%

DUKE ENERGY CAROLINAS

INTEGRATED RESOURCE PLAN

ATTACHMENT III

DUKE ENERGY CAROLINAS 2020 RESOURCE ADEQUACY STUDY

2020

III DUKE ENERGY CAROLINAS 2020 RESOURCE ADEQUACY STUDY

ASTRAPÉ CONSULTING
innovation in electric system planning

Duke Energy Carolinas

2020 Resource Adequacy Study

9/1/2020

PREPARED FOR

Duke Energy

PREPARED BY

Kevin Carden
Nick Wintermantel
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Astrapé Consulting

Contents

Executive Summary

This study was performed by Astrapé Consulting at the request of Duke Energy Carolinas (DEC) as an update to the study performed in 2016. The primary purpose of this study is to provide Duke system planners with information on physical reliability and costs that could be expected with various reserve margin[1] planning targets. Physical reliability refers to the frequency of firm load shed events and is calculated using Loss of Load Expectation (LOLE). The one day in 10-year standard (LOLE of 0.1) is interpreted as one day with one or more hours of firm load shed every 10 years due to a shortage of generating capacity and is used across the industry[2] to set minimum target reserve margin levels. Astrapé determined the reserve margin required to meet the one day in 10-year standard for the Base Case and multiple sensitivities included in the study. The study includes a Confidential Appendix containing confidential information such as fuel costs, outage rate data and transmission assumptions.

Customers expect to have electricity during all times of the year but especially during extreme weather conditions such as cold winter days when resource adequacy[3] is at risk for DEC[4]. In order

[1] Throughout this report, winter and summer reserve margins are defined by the formula: (installed capacity - peak load) / peak load. Installed capacity includes capacity value for intermittent resources such as solar and energy limited resources such as battery.

[2] https://www.ferc.gov/sites/default/files/2020-05/02-07-14-consultant-report.pdf; See Table 14 in A-1. PJM, MISO, NYISO ISO-NE, Quebec, IESO, FRCC, APS, NV Energy all use the 1 day in 10 year standard. As of this report, it is Astrapé's understanding that Southern Company has shifted to the greater of the economic reserve margin or the 1 day in 10 year standard.

[3] NERC RAPA Definition of "Adequacy" - The ability of the electric system to supply the aggregate electric power and energy requirements of the electricity consumers at all times, taking into account scheduled and expected unscheduled outages of system components. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2019.pdf, at 9.

[4] Section (b)(4)(iv) of NCUC Rule R8-61 (Certificate of Public Convenience and Necessity for Construction of Electric Generation Facilities) requires the utility to provide "… a verified statement as to whether the facility will be capable of operating during the lowest temperature that has been recorded in the area using information from the National Weather Service Automated Surface Observing System (ASOS) First Order Station in Asheville, Charlotte, Greensboro, Hatteras, Raleigh or Wilmington, depending upon the station that is located closest to where the plant will be located."

to ensure reliability during these peak periods, DEC maintains a minimum reserve margin level to manage unexpected conditions including extreme weather, load growth, and significant forced outages. To understand this risk, a wide distribution of possible scenarios must be simulated at a range of reserve margins. To calculate physical reliability and customer costs for the DEC system, Astrapé Consulting utilized a reliability model called SERVM (Strategic Energy and Risk Valuation Model) to perform thousands of hourly simulations for the 2024 study year at various reserve margin levels. Each of the yearly simulations was developed through a combination of deterministic and stochastic modeling of the uncertainty of weather, economic growth, unit availability, and neighbor assistance.

In the 2016 study, reliability risk was concentrated in the winter and the study determined that a 16.5% reserve margin was required to meet the one day in 10-year standard (LOLE of 0.1), for DEC. Because DEC's sister utility DEP required a 17.5% reserve margin to meet the same reliability standard, Duke Energy averaged the studies and used a 17% planning reserve margin target for both companies in its Integrated Resource Plan (IRP). This 2020 Study updates all input assumptions to reassess resource adequacy. As part of the update, several stakeholder meetings occurred to discuss inputs, methodology, and results. These stakeholder meetings included representatives from the North Carolina Public Staff, the South Carolina Office of Regulatory Staff (ORS), and the North Carolina Attorney General's Office. Following the initial meeting with stakeholders on February 21, 2020, the parties agreed to the key assumptions and sensitivities listed in Appendix A, Table A.1.

Preliminary results were presented to the stakeholders on May 8, 2020 and additional follow up was done throughout the month of May. Moving from the 2016 Study, the Study Year was shifted from 2019 to 2024 and assumed solar capacity was updated to the most recent projections. Because solar projections increased, LOLE has continued to shift from the summer to the winter. The high volatility in peak winter loads seen in the 2016 Study remained evident in recent historical data. In response to stakeholder feedback, the four year ahead economic load forecast error was dampened by providing a higher probability weighting on over-forecasting scenarios relative to under-forecasting scenarios. The net effect of the new distribution is to slightly reduce the target reserve margin compared to the previous distribution supplying slight upward pressure on the target reserve margin. This means that if the target reserve margin from this study is adopted, no reserves would be held for potential under-forecast of load growth. Generator outages remained in line with 2016 expectations, but additional cold weather outages of 260 MW for DEC were included for temperatures less than 10 degrees.

Physical Reliability Results-Island

Table ES1 shows the monthly contribution of LOLE at various reserve margin levels for the Island scenario. In this scenario, it is assumed that DEC is responsible for its own load and that there is no assistance from neighboring utilities. The summer and winter reserve margins differ for all scenarios due to seasonal demand forecast differences, weather-related thermal generation capacity differences, demand response seasonal availability, and seasonal solar capacity value. Using the one day in 10-year standard (LOLE of 0.1), which is used across the industry to set minimum target reserve margin levels, DEC would require a 22.5% winter reserve margin in the Island Case where no assistance from neighboring systems was assumed.

Given the significant level of solar on the system, the summer reserves are approximately 2% greater than winter reserves which results in essentially no reliability risk in the summer months when total LOLE is 0.1 days per year. This 22.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEC system. As discussed below, when compared to Base Case results which recognizes neighbor assistance, results of the Island Case illustrate both the benefits and risks of carrying lower reserve margins through reliance on neighboring systems.

Table ES1. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	12.4%	0.81	0.14	0.08	-	0.00	0.12	0.70	0.80	0.31	0.11	0.02	0.27	2.05	1.31	3.36
11.0%	13.3%	0.69	0.12	0.06	-	0.00	0.09	0.48	0.51	0.19	0.07	0.01	0.20	1.35	1.09	2.44
12.0%	14.2%	0.58	0.10	0.05	-	0.00	0.06	0.31	0.33	0.12	0.04	0.01	0.15	0.87	0.88	1.75
13.0%	15.0%	0.48	0.08	0.04	-	0.00	0.04	0.19	0.21	0.07	0.03	0.00	0.11	0.55	0.71	1.26
14.0%	15.9%	0.40	0.07	0.03	-	0.00	0.02	0.11	0.14	0.04	0.02	0.00	0.08	0.34	0.58	0.92
15.0%	16.8%	0.33	0.06	0.03	-	-	0.02	0.07	0.09	0.03	0.01	-	0.06	0.21	0.47	0.68
16.0%	17.6%	0.28	0.05	0.02	-	-	0.01	0.04	0.05	0.02	0.01	-	0.04	0.13	0.39	0.52
17.0%	18.5%	0.23	0.04	0.02	-	-	0.01	0.03	0.03	0.01	0.00	-	0.03	0.09	0.32	0.41
18.0%	19.4%	0.19	0.03	0.01	-	-	0.01	0.02	0.02	0.01	0.00	-	0.03	0.06	0.27	0.33
19.0%	20.2%	0.16	0.03	0.01	-	-	0.01	0.02	0.01	0.00	-	-	0.02	0.04	0.22	0.26
20.0%	21.1%	0.13	0.02	0.01	-	-	0.00	0.01	0.01	0.00	-	-	0.02	0.02	0.18	0.20
21.0%	22.0%	0.11	0.02	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.14	0.15
22.0%	22.8%	0.08	0.01	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.10	0.11
23.0%	23.7%	0.06	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.08	0.08
24.0%	24.6%	0.05	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.06	0.06

Physical Reliability Results-Base Case

Astrapé recognizes that DEC is part of the larger eastern interconnection and models neighbors one tie away to allow for market assistance during peak load periods. However, it is important to also understand that there is risk in relying on neighboring capacity that is less dependable than owned or contracted generation in which DEC would have first call rights. While there are certainly advantages of being interconnected due to weather diversity and generator outage diversity across regions, market assistance is not guaranteed and Astrapé believes Duke Energy has taken a moderate to aggressive approach (i.e. taking significant credit for neighboring regions) to modeling neighboring assistance compared to other surrounding entities such as PJM Interconnection L.L.C. (PJM)[5] and the Midcontinent Independent System Operator (MISO)[6]. A full description of the market assistance modeling and topology is available in the body of the report. Table ES2 shows the monthly LOLE at various reserve margin levels for the Base Case scenario which is the Island scenario with neighbor assistance included.[7]

[5] PJM limits market assistance to 3,500 MW which represents approximately 2.3% of its reserve margin compared to 6.5% assumed for DEC. https://www.pjm.com/-/media/committees-groups/subcommittees/raas/20191008/20191008-pjm-reserve-requirement-study-draft-2019.ashx – page 11
[6]MISO limits external assistance to a Unforced Capacity (UCAP) of 2,331 MW which represents approximately 1.8% of its reserve margin compared to 6.5% assumed for DEC. https://www.misoenergy.org/api/documents/getbymediaid/80578 page 24 (copy and paste link in browser)
[7] Reference Appendix B, Table B.1 for percentage of loss of load by month and hour of day for the Base Case.

Table ES2. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
5.00%	8.11%	0.21	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.05	0.33	0.38
6.00%	8.97%	0.20	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.04	0.30	0.35
7.00%	9.84%	0.18	0.05	0.02	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.04	0.28	0.31
8.00%	10.71%	0.17	0.04	0.01	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.03	0.25	0.28
9.00%	11.57%	0.15	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03	0.03	0.23	0.25
10.00%	12.44%	0.14	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.21	0.23
11.00%	13.31%	0.13	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.18	0.20
12.00%	14.18%	0.11	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.16	0.18
13.00%	15.04%	0.10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.15	0.15
14.00%	15.91%	0.09	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.13	0.13
15.00%	16.78%	0.08	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.12
16.00%	17.64%	0.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
17.00%	18.51%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
18.00%	19.38%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07
19.00%	20.24%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.06
20.00%	21.11%	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05
21.00%	21.98%	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04
22.00%	22.84%	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00-	0.03	0.03

As the table indicates, the required reserve margin to meet the one day in 10-year standard (LOLE of 0.1), is 16.00% which is 6.50% lower than the required reserve margin for 0.1 LOLE in the Island scenario. Approximately one third of the 22.5% required reserves is reduced due to interconnection ties. Astrapé also notes utilities around the country are continuing to retire and replace fossil-fuel resources with more intermittent or energy limited resources such as solar, wind, and battery capacity. For example, Dominion Energy Virginia has made substantial changes to its plans as this study was being conducted and plans to add substantial solar and other renewables to its system that could cause additional winter reliability stress than what is modeled. The below excerpt is from page 6 of Dominion Energy Virginia's 2020 IRP[8]:

> In the long term, based on current technology, other challenges will arise from the significant development of intermittent solar resources in all Alternative Plans. For example, based on the nature of solar resources, the Company will have excess capacity in the summer, but not enough capacity in the winter. Based on current technology, the Company would need to meet this winter deficit by either building additional energy storage resources or by buying capacity from the market. In addition, the Company would likely need to import a significant amount of energy during the winter, but would need to export or store significant amounts of energy during the spring and fall.

Additionally, PJM now considers the DOM Zone to be a winter peaking zone where winter peaks are projected to exceed summer peaks for the forecast period.[9] While this is only one example, these potential changes to surrounding resource mixes may lead to less confidence in market assistance for the future during early morning winter peak loads. Changes in neighboring system resource portfolios and load profiles will be an important consideration in future resource adequacy studies. To the extent historic diversification between DEC and neighboring systems declines, the historic reliability benefits DEC has experienced from being an interconnected system will also decline. It is worth nothing that after this study was completed, California experienced rolling blackouts during extreme weather conditions as the ability to rely on imported power has declined and has shifted away from dispatchable fossil-fuel resources and put greater reliance on intermittent resources.[10] It is premature to fully ascertain the lessons learned from the California load shed events. However, it does highlight the fact that as DEC reduces dependence on

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[8] https://cdn-dominionenergy-prd-001.azureedge.net/-/media/pdfs/global/2020-va-integrated-resource-plan.pdf?la=en&rev=fca793dd8eae4ebea4ee42f5642c9509
[9] Dominion Energy Virginia 2020 IRP, at 40.
[10] http://www.caiso.com/Documents/ISO-Stage-3-Emergency-Declaration-Lifted-Power-Restored-Statewide.pdf

dispatchable fossil fuels and increases dependence on intermittent resources, it is important to ensure it is done in a manner that does not impact reliability to customers.

Physical Reliability Results-DEC/DEP Combined Case

In addition to running the Island and Base Case scenarios, a DEC and DEP Combined Case scenario was simulated to see the reliability impact of DEC and DEP as a single balancing authority. In this scenario, DEC and DEP prioritize helping each other over their other external neighbors but also retain access to external market assistance. The various reserve margin levels are calculated as the total resources in both DEC and DEP using the combined coincident peak load, and reserve margins are increased together for the combined utilities. Table ES3 shows the results of the Combined Case which shows that a 16.75% combined reserve margin is needed to meet the 1 day in 10-year standard. An additional Combined Case sensitivity was simulated to assess the impact of a more constrained import limit. This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[11] resulting in an increase in the reserve margin from 16.75% to 18.0%.

Table ES3. Combined Case Physical Reliability Results

Sensitivity	1 in 10 LOLE Reserve Margin
Base Case	16.0%
Combined Target	16.75%
Combined Target 1,500 MW Import Limit	18.00%

[11] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

Results for the Combined Case and the individual Base Cases are outlined in the table below. The DEP results are documented in a separate report but show that a 19.25% reserve margin is required to meet the one day in 10-year standard (LOLE of 0.1).

Table ES4. Combined Case Differences

Region	1 in 10 LOLE Reserve Margin
DEC	16.00%
DEP	19.25%
Combined (Coincident)	16.75%

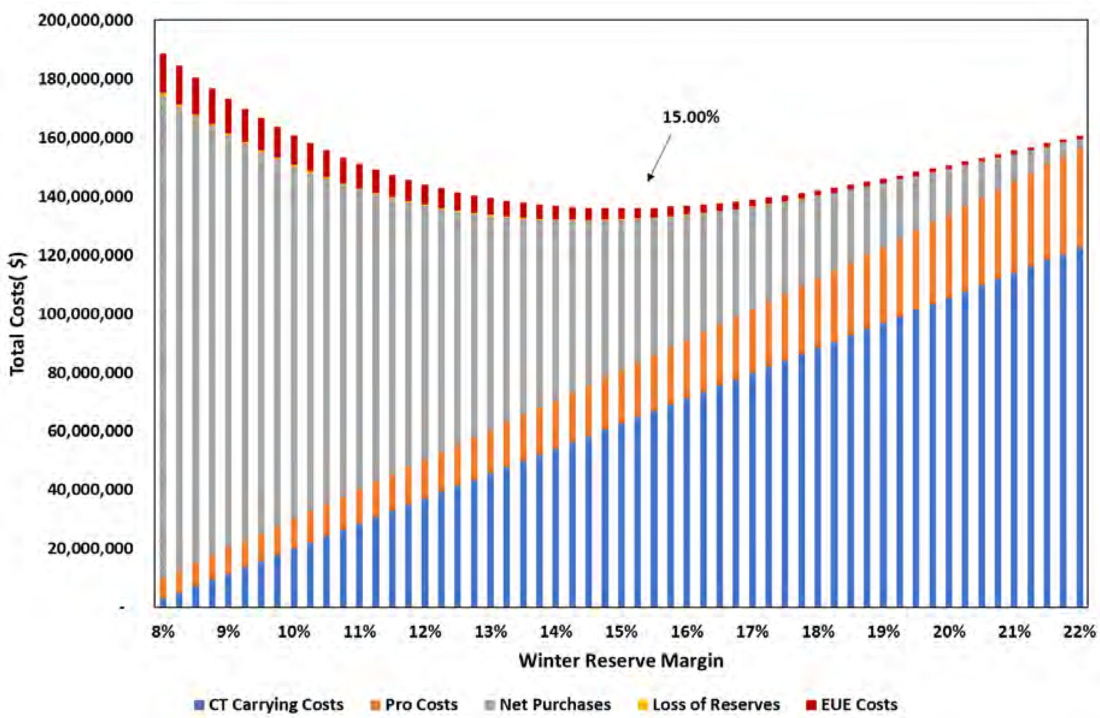
Economic Reliability Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs[12] were analyzed across reserve margin levels for the Base Case. Figure ES1 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and

[12] System costs = system energy costs plus capacity costs of incremental reserves. System energy costs include production costs + net purchases + loss of reserves costs + unserved energy costs while system capacity costs include the fixed capital and fixed operations & maintenance (FOM) costs for CT capacity. Unserved energy costs equal the value of lost load times the expected unserved energy

unit performance iterations at each reserve margin level and represents the yearly expected value on a year in and year out basis.

Figure ES1. Base Case Risk Neutral Economic Results[13]



As Figure ES1 shows, the lowest risk neutral cost falls at a 15.00% reserve margin very close to the one day in 10-year standard (LOLE of 0.1). These values are close because the summer reserve margins are only slightly higher than the winter reserve margins which increases the savings of adding additional CT capacity.[14] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from

[13] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEC has approximately 1.5 billion dollars in total costs.
[14] This is different than the results seen in DEP because DEP's summer reserves margins are much greater than its winter reserves margins causing CTs to provide less economic benefit in DEP than DEC.

either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure ES2, however, shows the distribution of system energy costs which includes production costs, purchase costs, loss of reserves costs, and expected unserved energy (EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margin levels to higher reserve margin levels, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

Figure ES2. System Energy Costs (Cumulative Probability Curves)

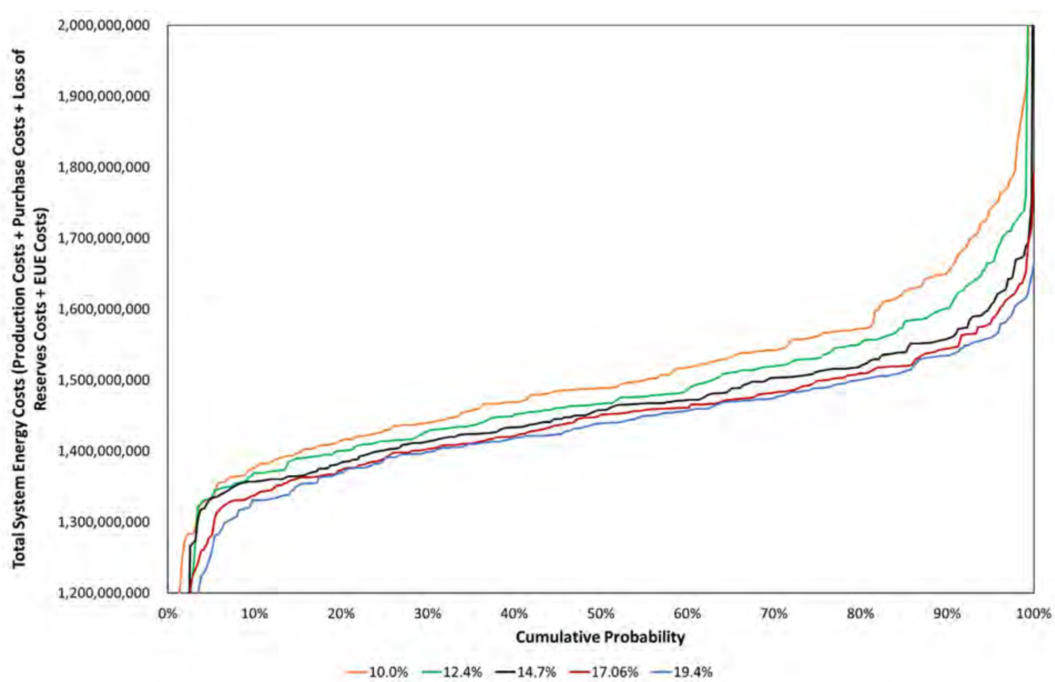


Table ES5 shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure ES1 as well as the energy savings at higher cumulative probability levels from Figure ES2. As shown in the table, going from the risk neutral reserve margin of 15.00% to 17% increases customer costs on average by $2.9 million a year[15] and reduces LOLE from 0.12 to 0.08 events per year. The LOLE for the island scenario decreases from 0.68 days per year to 0.41 days per year. However, 10% of the time energy savings are greater than or equal to $21 million if a 17% reserve margin is maintained versus the 15.00% reserve margin. While 5 % of the time, $34 million or more is saved.

Table ES5. Annual Customer Costs vs LOLE

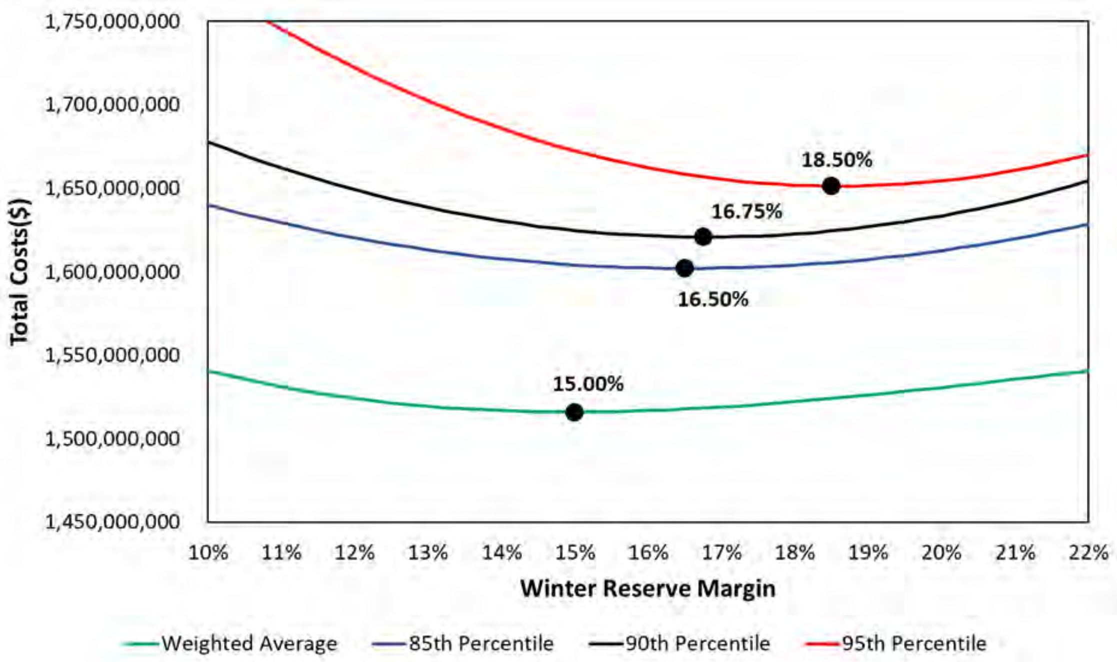
Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
15.00%	-	-	-	-	-	-	0.12	0.68
16.00%	8.5	-7.8	0.8	-10.4	-11.7	-18.6	0.1	0.52
17.00%	17.1	-14.2	2.9	-19.0	-21.0	-34.0	0.08	0.41
18.00%	25.6	-19.5	6.1	-25.8	-27.8	-46.1	0.07	0.33
19.00%	34.2	-24.0	10.1	-30.8	-32.1	-55.0	0.06	0.26
20.00%	42.7	-28.0	14.7	-34.1	-33.9	-60.6	0.05	0.20

The next figure takes the 85th, 90th, and 95th percentile points of the total system energy costs in Figure ES2 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher

[15] This includes $17 million for additional CT costs less $14 million of system energy savings.

cumulative probability points using the 85th – 95th percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 15.00% reserve margin, the 85th to 95th percentile cost curves point to a 16-19% reserve margin.

Figure ES3. Total System Costs by Reserve Margin.



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

Sensitivity Results

Various sensitivities were run in addition to the Base Case to examine the reliability and cost impact of different assumptions and scenarios. Table ES6 lists the various sensitivities and the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as well as economic results of each. These include sensitivities around cold weather generator outages, load forecast error uncertainty, solar penetration, the cost of unserved energy, the cost of CT capacity, demand response, coal retirements, and climate change. Detailed explanations of each sensitivity are available in the body of the report. The target reserve margin to meet the one day in 10-year standard (LOLE of 0.1) ranged from 14.75% to 17.25% depending on the sensitivity simulated.

Table ES6. Sensitivity Results

Sensitivity	1 in 10 LOLE Reserve Margin	Economic Risk Neutral	Economic 90th Percentile
Base Case	16.00%	15.00%	16.75%
No Cold Weather Outages	14.75%	14.75%	16.75%
Cold Weather Outages based on 2014 - 2019	17.25%	15.00%	17.00%
Remove LFE	16.25%	15.00%	16.00%
Originally Proposed Normal Distribution	17.00%	16.00%	18.00%
Low Solar	16.00%	16.00%	18.25%
High Solar	15.75%	14.00%	14.50%
CT costs 40 $/kW-yr	16.00%	16.00%	17.25%
CT costs 60 $/kW-yr	16.00%	13.75%	16.00%
EUE 5,000 $/MWh	16.00%	14.50%	16.25%
EUE 25,000 $/MWh	16.00%	15.25%	16.75%
Demand Response Winter as High as Summer	16.75%	18.25%	19.50%
Retire all Coal	15.25%	17.00%	20.25%
Climate Change	15.75%	14.25%	16.75%

Recommendation

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEP Study, Astrapé recommends that DEC continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEC utility would require a 22.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and that with market assistance, DEC would need to maintain a 16.00% reserve margin. However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 19.25% reserve margin required by DEP to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target for both DEC and DEP is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increase the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEC will never be forced to shed firm load during extreme conditions as DEC and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEC has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance which this study considers, firm load would have been shed. In addition, incorporation of tail end reliability risk in modeling should be from statistically and historically defendable methods; not from including subjective risks that cannot be assigned probability. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 15% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEC resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEC should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEC observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and in future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[16]

[16] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

I. List of Figures

II. List of Tables

III. Input Assumptions

A. Study Year

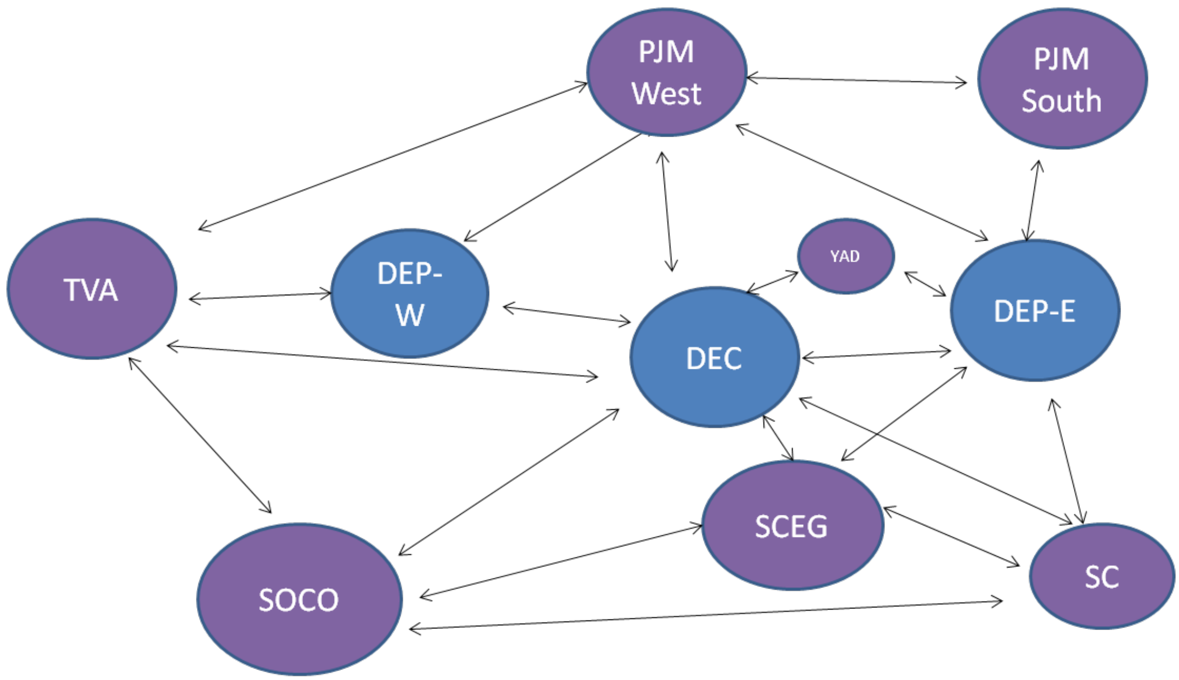
The selected study year is 2024[17]. The SERVM simulation results are broadly applicable to future years assuming that resource mixes and market structures do not change in a manner that shifts the reliability risk to a different season or different time of day.

B. Study Topology

Figure 1 shows the study topology that was used for the Resource Adequacy Study. While market assistance is not as dependable as resources that are utility owned or have firm contracts, Astrapé believes it is appropriate to capture the load diversity and generator outage diversity that DEC has with its neighbors. For this study, the DEC system was modeled with nine surrounding regions. The surrounding regions captured in the modeling included Duke Energy Progress (DEP) which was modeled in two interconnect zones: (1) DEP – E and (2) DEP – W, Tennessee Valley Authority (TVA), Southern Company (SOCO), PJM West &PJM South, Yadkin (YAD), Dominion Energy South Carolina (formally known as South Carolina Electric & Gas (SCEG)), and Santee Cooper (SC). SERVM uses a pipe and bubble representation in which energy can be shared based on economics but subject to transmission constraints.

[17] The year 2024 was chosen because it is four years into the future which is indicative of the amount of time needed to permit and construct a new generating facility.

Figure 1. Study Topology



Confidential Appendix Table CA1 displays the DEC import capability from surrounding regions including the amount set aside for Transmission Reliability Margin (TRM).

C. Load Modeling

Table 1 displays SERVM's modeled seasonal peak forecast net of energy efficiency programs for 2024.

Table 1. 2024 Forecast: DEC Seasonal Peak (MW)

2024 Summer	18,456 MW
2024 Winter	17,976 MW

To model the effects of weather uncertainty, thirty-nine historical weather years (1980 - 2018) were developed to reflect the impact of weather on load. Based on the last five years of historical weather and load[18], a neural network program was used to develop relationships between weather observations and load. The historical weather consisted of hourly temperatures from three weather stations across the DEC service territory. The weather stations included Charlotte, NC, Greensboro, NC, and Greenville, SC. Other inputs into the neural net model consisted of hour of week, eight hour rolling average temperatures, twenty-four hour rolling average temperatures, and forty-eight hour rolling average temperatures. Different weather to load relationships were built for the summer, winter, and shoulder seasons. These relationships were then applied to the last thirty-nine years of weather to develop thirty-nine synthetic load shapes for 2024. Equal probabilities were given to each of the thirty-nine load shapes in the simulation. The synthetic load shapes were scaled to align the normal summer and winter peaks to the Company's projected thirty-year weather normal load forecast for 2024.

Figures 2 and 3 show the results of the 2014-2019 weather load modeling by displaying the peak load variance for both the summer and winter seasons. The y-axis represents the percentage deviation from the average peak. For example, the 1985 synthetic load shape would result in a summer peak load approximately 2% below normal and a winter peak load approximately 18% above normal. Thus, the bars represent the variance in projected peak loads based on weather experienced during the historic weather years. It should be noted that the variance for winter is much greater than summer. As an example, extreme cold temperatures can cause load to spike from additional electric strip heating. The highest summer temperatures typically are only a few degrees above the expected highest temperature and therefore do not produce as much peak load variation.

[18] The historical load included years 2014 through September of 2019.

Figure 2. DEC Summer Peak Weather Variability

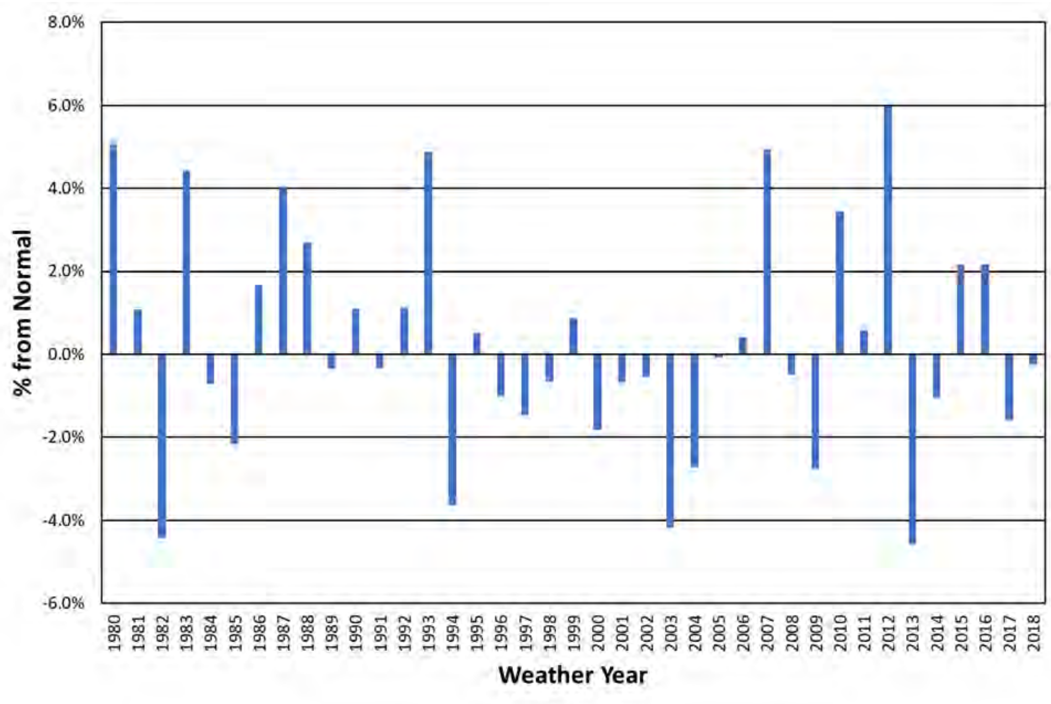


Figure 3. DEC Winter Peak Weather Variability

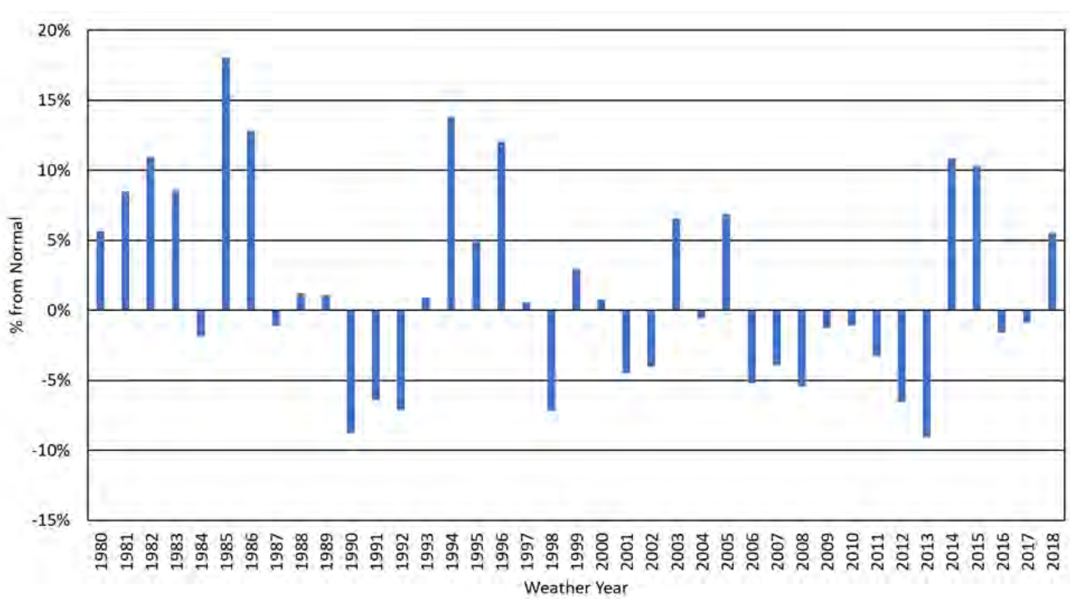
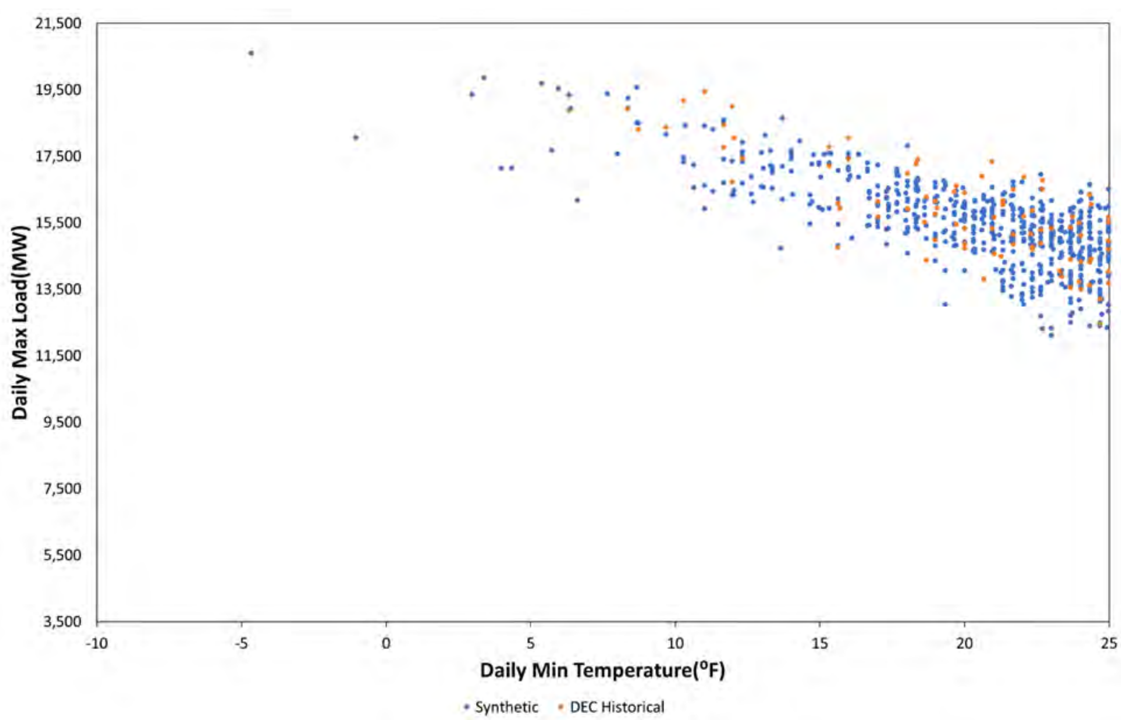


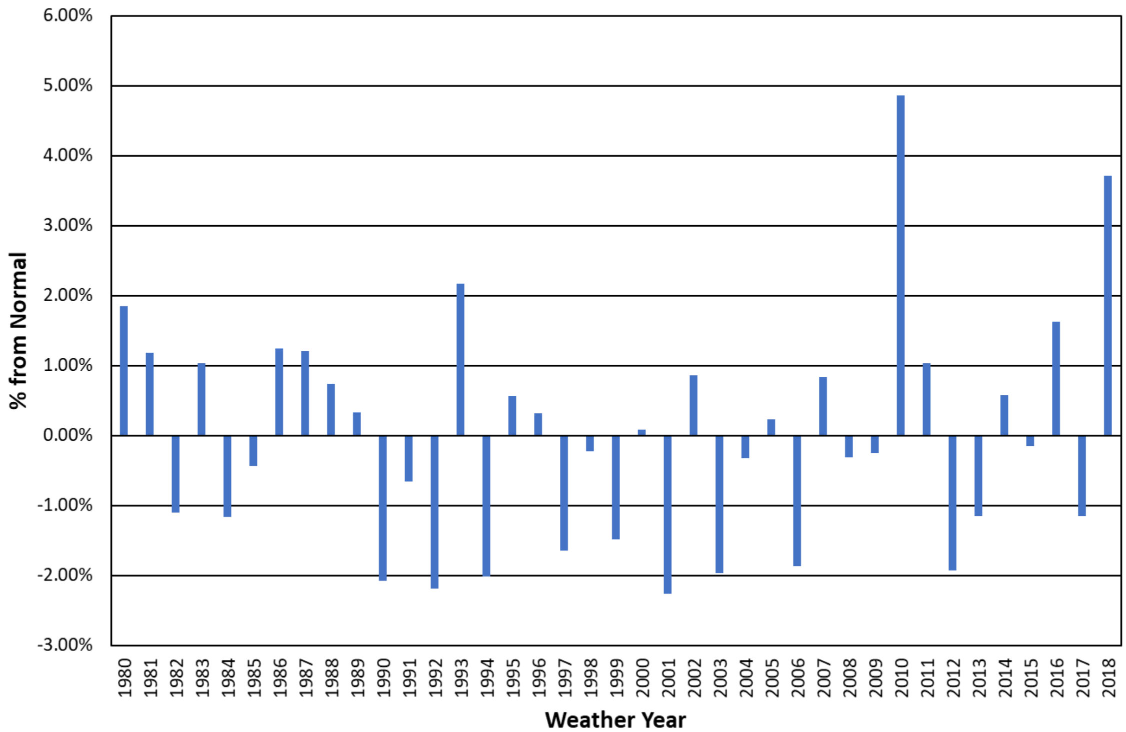
Figure 4 shows a daily peak load comparison of the synthetic load shapes and DEC history as a function of temperature. The predicted values align well with the history. Because recent historical observations only recorded a single minimum temperature of six degrees Fahrenheit, Astrapé estimated the extrapolation for extreme cold weather days using regression analysis on the historical data. This figure highlights that the frequency of cold weather events is captured as it has been seen in history.

Figure 4. DEC Winter Calibration



The energy variation is lower than peak variation across the weather years as expected. As shown in Figure 5, 2010 was an extreme year in total energy due to persistent severe temperatures across the summer and yet the deviation from average was only 5%.

Figure 5. DEC Annual Energy Variability



The synthetic shapes described above were then scaled to the forecasted seasonal energy and peaks within SERVM. Because DEC's load forecast is based on thirty years of weather, the shapes were scaled so that the average of the last thirty years equaled the forecast.

Synthetic loads for each external region were developed in a similar manner as the DEC loads. A relationship between hourly weather and publicly available hourly load[19] was developed based on

[19] Federal Energy Regulatory Commission (FERC) 714 Forms were accessed during January of 2020 to pull hourly historical load for all neighboring regions.

recent history, and then this relationship was applied to thirty-nine years of weather data to develop thirty-nine synthetic load shapes. Tables 2 and 3 show the resulting weather diversity between DEC and external regions for both summer and winter loads. When the system, which includes all regions in the study, is at its winter peak, the individual regions are approximately 2% - 9% below their non-coincidental peak load on average over the thirty-nine year period, resulting in an average system diversity of 4.7%. When DEC is at its winter peak load, DEP is 2.8% below its peak load on average while other regions are approximately 3% - 11% below their winter peak loads on average. Similar values are seen during the summer.

Table 2. External Region Summer Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	3.4%	3.8%	5.2%	4.2%	6.8%	7.0%	3.7%	1.4%	N/A
At DEC Peak	N/A	2.6%	7.0%	4.8%	5.7%	7.5%	4.5%	6.9%	2.3%

Table 3. External Region Winter Load Diversity

Load Diversity (% below non coincident average peak)	DEC	DEP	SOCO	TVA	SC	SCEG	PJM S	PJM W	System
At System Coincident Peak	2.5%	2.8%	2.8%	5.8%	8.9%	4.8%	6.9%	3.2%	N/A
At DEC Peak	N/A	2.8%	3.0%	5.8%	9.2%	5.9%	7.0%	11.0%	2.8%

D. Economic Load Forecast Error

Economic load forecast error multipliers were developed to isolate the economic uncertainty that Duke has in its four year ahead load forecasts. Four years is an approximation for the amount of time it takes to build a new resource or otherwise significantly change resource plans. To estimate the economic load forecast error, the difference between Congressional Budget Office (CBO) Gross Domestic Product (GDP) forecasts four years ahead and actual data was fit to a distribution which weighted over-forecasting more heavily than under-forecasting load[20]. This was a direct change accepted as part of the feedback in stakeholder meetings.[21] Because electric load grows at a slower rate than GDP, a 40% multiplier was applied to the raw CBO forecast error distribution. Table 4 shows the economic load forecast multipliers and associated probabilities. As an illustration, 25% of the time, it is expected that load will be over-forecasted by 2.7% four years out. Within the simulations, when DEC over-forecasts load, the external regions also over-forecast load. The SERVM model utilized each of the thirty-nine weather years and applied each of these five load forecast error points to create 195 different load scenarios. Each weather year was given an equal probability of occurrence.

Table 4. Load Forecast Error

Load Forecast Error Multipliers	Probability %
0.958	10.0%
0.973	25.0%
1.00	40.0%
1.02	15.0%
1.031	10.0%

[20] CBO's Economic Forecasting Record: 2017 Update. www.cbo.gov/publication/53090
www.cbo.gov/publication/53090
[21] Including the economic load forecast uncertainty actually results in a lower reserve margin compared to a scenario that excludes the load forecast uncertainty since over-forecasting load is weighted more heavily than under-forecasting load.

E. Conventional Thermal Resources

DEC resources are outlined in Tables 5 and 6 and represent summer ratings and winter ratings. All thermal resources are committed and dispatched to load economically. The capacities of the units are defined as a function of temperature in the simulations. Full winter rating is achieved at 35°F and below and summer rating is assumed for 95° and above. For temperatures in between 35°F and 95°F, a simple linear regression between the summer and winter rating was utilized for each unit.

Table 5. DEC Baseload and Intermediate Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Allen 1	Coal	162	167	Marshall 4	Coal	660	660
Allen 2	Coal	162	167	Catawba 1	Nuclear	260	294
Allen 3	Coal	258	270	Catawba 2	Nuclear	260	294
Allen 4	Coal	257	267	McGuire 1	Nuclear	1158	1199
Allen 5	Coal	259	259	McGuire 2	Nuclear	1158	1187
Belews Creek 1	Coal	1110	1110	Oconee 1	Nuclear	847	865
Belews Creek 2	Coal	1110	1110	Oconee 2	Nuclear	848	872
Cliffside 5	Coal	554	546	Oconee 3	Nuclear	859	881
Cliffside 6	Coal	844	849	Buck CC	Combined Cycle	668	716
Marshall 1	Coal	370	380	Dan River CC	Combined Cycle	662	718
Marshall 2	Coal	370	380	Lee CC	Combined Cycle	686	692
Marshall 3	Coal	658	658	Lee NG Conversion	Natural Gas	160	173

Table 6. DEC Peaking Resources

Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)	Unit Name	Resource Type	Summer Capacity (MW)	Winter Capacity (MW)
Lincoln CT_1	NG Peaker	76	98	Lee CT_1	Oil Peaker	42	48
Lincoln CT_2	NG Peaker	76	99	Lee CT_2	Oil Peaker	42	48
Lincoln CT_3	NG Peaker	75	99	Mill_Creek_CT_1	NG Peaker	71	95
Lincoln CT_4	NG Peaker	75	98	Mill_Creek_CT_2	NG Peaker	70	95
Lincoln CT_5	NG Peaker	74	97	Mill_Creek_CT_3	NG Peaker	71	95
Lincoln CT_6	NG Peaker	73	97	Mill_Creek_CT_4	NG Peaker	70	96
Lincoln CT_7	NG Peaker	75	98	Mill_Creek_CT_5	NG Peaker	69	96
Lincoln CT_8	NG Peaker	75	98	Mill_Creek_CT_6	NG Peaker	71	92
Lincoln CT_9	NG Peaker	75	97	Mill_Creek_CT_7	NG Peaker	70	95
Lincoln CT_10	NG Peaker	75	98	Mill_Creek_CT_8	NG Peaker	71	93
Lincoln CT_11	NG Peaker	74	98	Rockingham 1	NG Peaker	165	179
Lincoln CT_12	NG Peaker	75	98	Rockingham 2	NG Peaker	165	179
Lincoln CT_13	NG Peaker	74	98	Rockingham 3	NG Peaker	165	179
Lincoln CT_14	NG Peaker	74	97	Rockingham 4	NG Peaker	165	179
Lincoln CT_15	NG Peaker	73	98	Rockingham 5	NG Peaker	165	179
Lincoln CT_16	NG Peaker	73	97				

DEC purchase contracts were modeled as shown in Confidential Appendix Table CA2. These resources were treated as traditional thermal resources and counted towards reserve margin. Confidential Appendix Table CA3 shows the fuel prices used in the study for DEC and its neighboring power systems.

F. Unit Outage Data

Unlike typical production cost models, SERVM does not use an Equivalent Forced Outage Rate (EFOR) for each unit as an input. Instead, historical Generating Availability Data System (GADS) data events for the period 2014-2019 are entered in for each unit and SERVM randomly draws from these events to simulate the unit outages. Units without historical data use history from similar technologies. The events are entered using the following variables:

Full Outage Modeling
Time-to-Repair Hours
Time-to-Fail Hours

Partial Outage Modeling
Partial Outage Time-to-Repair Hours
Partial Outage Derate Percentage
Partial Outage Time-to-Fail Hours

Maintenance Outages
Maintenance Outage Rate - % of time in a month that the unit will be on maintenance outage. SERVM uses this percentage and schedules the maintenance outages during off peak periods.

Planned Outages
The actual schedule for 2024 was used.

To illustrate the outage logic, assume that from 2014 – 2019, a generator had 15 full outage events and 30 partial outage events reported in the GADS data. The Time-to-Repair and Time-to-Fail between each event is calculated from the GADS data. These multiple Time-to-Repair and Time-to-Fail inputs are the distributions used by SERVM. Because there may be seasonal variances in EFOR, the data is broken up into seasons such that there is a set of Time-to-Repair and Time-to-Fail inputs for summer, shoulder, and winter, based on history. Further, assume the generator is online in hour 1 of the simulation. SERVM will randomly draw both a full outage and partial outage Time-to-Fail value from the distributions provided. Once the unit has been economically dispatched for that amount of time, it will fail. A partial outage will be triggered first if the selected Time-to-Fail value is lower than the selected full outage Time-to-Fail value. Next, the model will draw a Time-to-Repair value from the distribution and be on outage for that number of hours. When the repair is complete it will draw a new Time-to-Fail value. The process repeats until the end of the iteration when it will begin again for the subsequent iteration. The full outage counters and partial outage counters run in parallel. This more detailed modeling is important to capture the tails of the distribution that a simple convolution method would not capture. Confidential Appendix Table CA4 shows system peak season Equivalent Forced Outage Rate (EFOR) for the system and by unit.

The most important aspect of unit performance modeling in resource adequacy studies is the cumulative MW offline distribution. Most service reliability problems are due to significant coincident outages. Confidential Appendix Figure CA1 shows the distribution of modeled system outages as a percentage of time modeled and compared well with actual historical data.

Additional analysis was performed to understand the impact cold temperatures have on system outages. Confidential Appendix Figures CA2 and CA3 show the difference in cold weather outages during the 2014-2019 period and the 2016-2019 period. The 2014-2019 period showed more events than the 2016-2019 period which is logical because Duke Energy has put practices in place to enhance reliability during these periods, however the 2016 – 2019 data shows some events still occur. The average capacity offline below 10 degrees for DEC and DEP combined was 400 MW. Astrapé split this value by peak load ratio and included 260 MW in the DEC Study and 140 MW in the DEP Study at temperatures below 10 degrees. Sensitivities were performed with the cold weather outages removed and increased to match the 2014 – 2019 dataset which showed an average of 800 MW offline on days below 10 degrees. The MWs offline during the 10 coldest days can be seen in Confidential Appendix Table CA5. The outages shown are only events that included some type of freezing or cold weather problem as part of the description in the outage event.

G. Solar and Battery Modeling

Table 7 shows the solar and battery resources captured in the study.

Table 7. DEC Renewable Resources Excluding Existing Hydro

Unit Type	Summer Capacity (MW)	Winter Capacity (MW)	Modeling
Utility Owned-Fixed	85	85	Hourly Profiles
Transition-Fixed	660	660	Hourly Profiles
CPRE Tranche 1 Fixed 40%/Tracking 60%	465	465	Hourly Profiles
Future Solar Fixed 40%/Tracking 60%	1,368	1,368	Hourly Profiles
Total	2,578	2,578	
Total Battery	146	146	Modeled as energy arbitrage

The solar units were simulated with thirty-nine solar shapes representing thirty-nine years of weather. The solar shapes were developed by Astrapé from data downloaded from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) Data Viewer. The data was then input into NREL's System Advisor Model (SAM) for each year and county to generate hourly profiles for both fixed and tracking solar profiles. The solar capacity was given 37% credit in the summer and 1% in the winter for reserve margin calculations based on the 2018 Solar Capacity Value Study. The following figure shows the county locations that were used and Figure 7 shows the average August output for different fixed-tilt and single-axis-tracking inverter loading ratios.

Figure 6. Solar Map

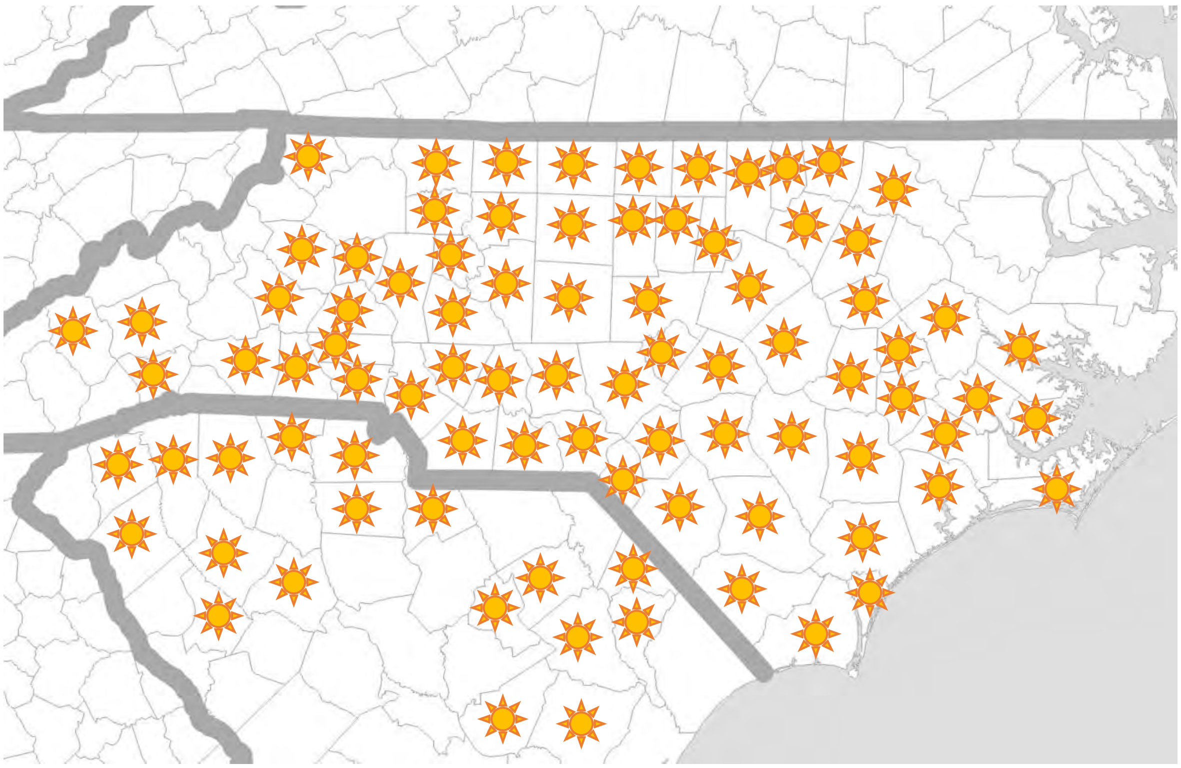
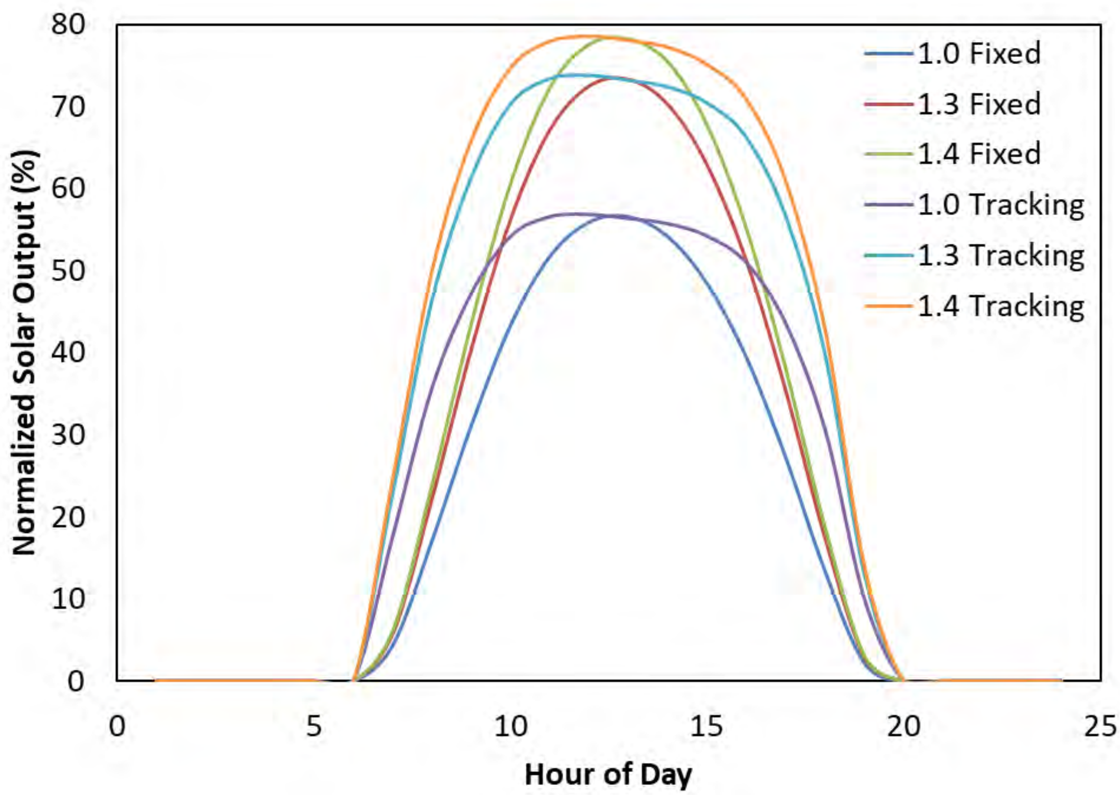


Figure 7. Average August Output for Different Inverter Loading Ratios



H. Hydro Modeling

The scheduled hydro is used for shaving the daily peak load but also includes minimum flow requirements. Figure 8 shows the total breakdown of scheduled hydro based on the last thirty-nine years of weather.

Figure 8. Scheduled Capacity

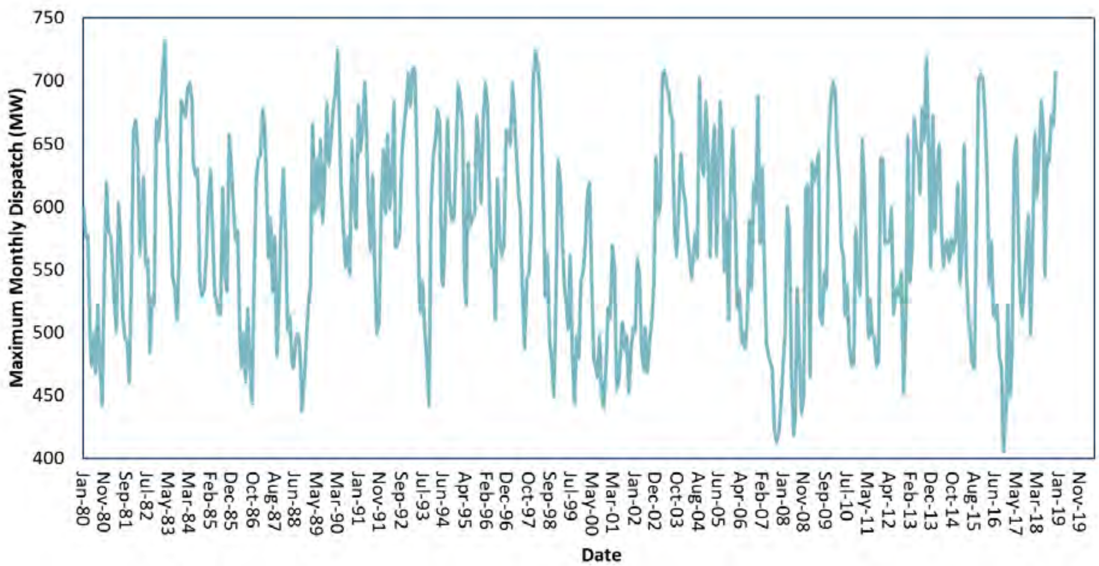
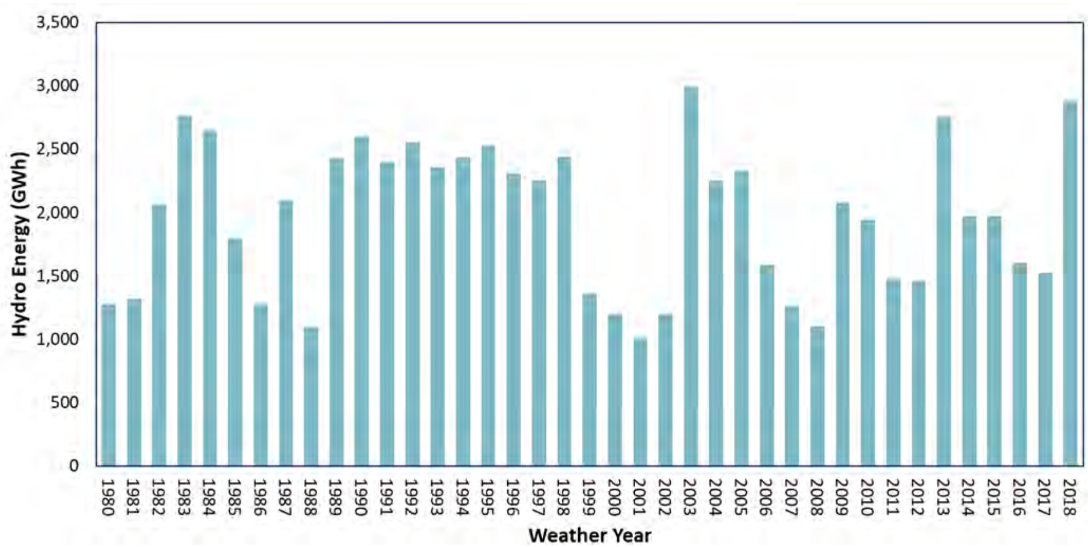


Figure 9 demonstrates the variation of hydro energy by weather year which is input into the model. The lower rainfall years such as 2001, 2007, and 2008 are captured in the reliability model with lower peak shaving as shown in Figure 9.

Figure 9. Hydro Energy by Weather Year



In addition to conventional hydro, DEC owns and operates a pump hydro fleet consisting of 2,400 MW. The fleet consists of two pump storage plants: (1) Bad Creek at a 1,620 MW summer/winter rating and (2) Jocassee at a 780 MW summer/winter rating. These resources are modeled with reservoir capacity, pumping efficiency, pumping capacity, generating capacity, and forced outage rates[22]. SERVM uses excess capacity to economically fill up the reservoirs to ensure the generating capacity is available during peak conditions.

I. Demand Response Modeling

Demand response programs are modeled as resources in the simulations. They are modeled with specific contract limits including hours per year, days per week, and hours per day constraints. For this study, 1,122 MW of summer capacity and 442 MW of winter capacity were included as shown in Table 8. To ensure these resources were called after conventional generation, a $2,000/MWh strike price was included.

[22] See Confidential Appendix Table CA4

Table 8. DEC Demand Response Modeling

Region	Program	Summer Capacity (MW)	Winter Capacity (MW)	Hours Per Year	Days Per Week	Hours Per Day
DEC	PowerShare Mandatory	355	331	150	7	24
DEC	PowerShare Generator	11	10	100	7	10
DEC	Power Manager DLC	608	0	100	7	10
DEC	IS	94	89	150	7	10
DEC	Energy Wise Business	46	4	60	7	4
DEC	SG	8	8	150	7	24
	Total DEC	1,122	442			

J. Operating Reserve Requirements

The operating reserves assumed for DEC are shown below. SERVM commits to this level of operating reserves in all hours. However, all operating reserves except for the 218 MW of regulation are allowed to be depleted during a firm load shed event.

- Regulation Up/Down: 218 MW
- Spinning Requirement: 275 MW
- Non-Spin Requirement: 275 MW
- Additional Load Following Due to Intermittent Resources in 2024: Hourly values were used based on a 12x24 profile provided by Duke Energy from its internal modeling.

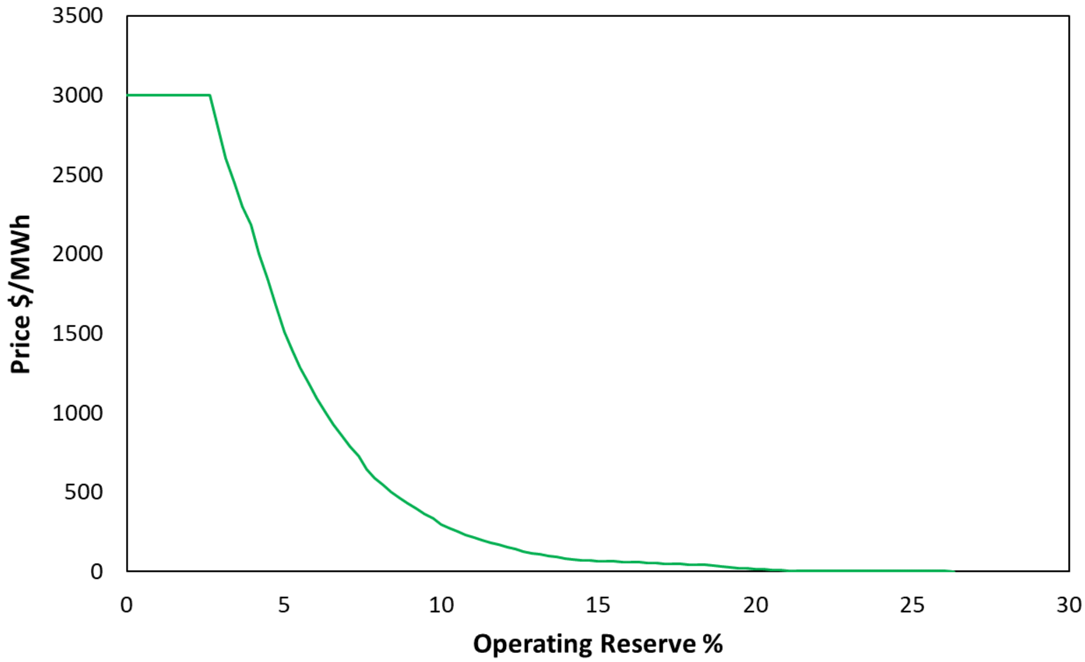
K. External Assistance Modeling

The external market plays a significant role in planning for resource adequacy. If several of the DEC resources were experiencing an outage at the same time, and DEC did not have access to surrounding markets, there is a high likelihood of unserved load. To capture a reasonable amount of assistance from surrounding neighbors, each neighbor was modeled at the one day in 10-year standard (LOLE of 0.1) level representing the target for many entities. By modeling in this manner, only weather diversity and generator outage diversity benefits are captured. The market representation used in SERVM is based on Astrapé's proprietary dataset which is developed based on FERC Forms, Energy Information Administration (EIA) Forms, and reviews of IRP information from neighboring regions. To ensure purchases in the model compared well in magnitude to historical data, the years 2015 and 2018 were simulated since they reflected cold weather years with high winter peaks. Figure CA4 in the confidential appendix shows that calibration with purchases on the y-axis and load on the x-axis for the 2015 and 2018 weather years. The actual purchases and modeled results show DEC purchases significant capacity during high load hours during these years.

The cost of transfers between regions is based on marginal costs. In cases where a region is short of resources, scarcity pricing is added to the marginal costs. As a region's hourly reserves approach zero, the scarcity pricing for that region increases. Figure 10 shows the scarcity pricing curve that was used in the simulations. It should be noted that the frequency of these scarcity prices is very low because in the majority of hours, there is plenty of capacity to meet load after the market has cleared[23].

[23]The market clearing algorithm within SERVM attempts to get all regions to the same price subject to transmission constraints. So, if a region's original price is $3,000/MWh based on the conditions and scarcity pricing in that region alone, it is highly probable that a surrounding region will provide enough capacity to that region to bring prices down to reasonable levels.

Figure 10. Operating Reserve Demand Curve (ORDC)



L. Cost of Unserved Energy

Unserved energy costs were derived from national studies completed for the Department of Energy (DOE) in 2003[24] and 2009[25], along with three other studies performed[26] previously by other consultants. The DOE studies were compilations of other surveys performed by utilities over the last two decades. All studies split the customer class categories into residential, commercial, and industrial. The values were then applied to the actual DEC customer class mix to develop a wide range of costs for unserved energy. Table 9 shows those results. Because expected unserved

[24] https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-54365.pdf
[25] https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf https://eta-publications.lbl.gov/sites/default/files/lbnl-2132e.pdf
[26] https://pdfs.semanticscholar.org/544b/d740304b64752b451d749221a00eede4c700.pdf Peter Cramton, Jeffrey Lien. Value of Lost Load. February 14, 2000.

energy costs are so low near the economic optimum reserve margin, this value, while high in magnitude, is not a significant driver in the economic analysis. Since the public estimates ranged significantly, DEC used $18,160/MWh for the Base Case in 2024, and sensitivities were performed around this value from $5,000 MWh to $25,000 MWh to understand the impact.

Table 9. Unserved Energy Costs / Value of Lost Load

	Weightings	2003 DOE Study 2024 $/kW-yr	2009 DOE Study 2024 $/kW-yr	Christiansen Associates 2024 $/kW-yr	Billinton and Wacker 2024 $/kW-yr	Karuiki and Allan 2024 $/kW-yr
Residential	36%	1.57	1.50	3.12	2.73	1.26
Commercial	37%	35.54	109.23	22.37	23.24	24.74
Industrial	26%	20.51	32.53	11.59	23.24	58.65
	Weighted Average $/kWh	19.25	49.96	12.54	15.78	25.08
	Average $/kWh	24.52				
	Average $/kWh excluding the 2009 DOE Study	18.16				

M. System Capacity Carrying Costs

The study assumes that the cheapest marginal resource is utilized to calculate the carrying cost of additional capacity. The cost of carrying incremental reserves was based on the capital and FOM of a new simple cycle natural gas Combustion Turbine (CT) consistent with the Company's IRP assumptions. For the study, the cost of each additional kW of reserves can be found in Confidential Appendix Table CA6. The additional CT units were forced to have a 5% EFOR in the simulations and used to vary reserve margin in the study.

IV. Simulation Methodology

Since most reliability events are high impact, low probability events, a large number of scenarios must be considered. For DEC, SERVM utilized thirty-nine years of historical weather and load shapes, five points of economic load growth forecast error, and fifteen iterations of unit outage draws for each scenario to represent a distribution of realistic scenarios. The number of yearly simulation cases equals 39 weather years * 5 load forecast errors * 15 unit outage iterations = 2,925 total iterations for the Base Case. This Base Case, comprised of 2,925 total iterations, was re-run at different reserve margin levels by varying the amount of CT capacity.

A. Case Probabilities

An example of probabilities given for each case is shown in Table 10. Each weather year is given equal probability and each weather year is multiplied by the probability of each load forecast error point to calculate the case probability.

Table 10. Case Probability Example

Weather Year	Weather Year Probability (%)	Load multipliers Due to Load Economic Forecast Error (%)	Load Economic Forecast Error Probability (%)	Case Probability (%)
1980	2.56	95.8	10	0.256
1980	2.56	97.3	25	0.64
1980	2.56	100	40	1.024
1980	2.56	102	15	0.384
1980	2.56	103.1	10	0.256
1981	2.56	95.8	10	0.256
1981	2.56	97.3	25	0.64
1981	2.56	100	40	1.024
1981	2.56	102	15	0.384
1981	2.56	103.1	10	0.256
1982	2.56	95.8	10	0.256

1982	2.56	97.3	25	0.64
1982	2.56	100	40	1.024
1982	2.56	102	15	0.384
1982	2.56	103.1	10	0.256
...	...	...	...	...
...	...	...	...	...
2018	2.56	103.1	10	0.256
			Total	100

For this study, LOLE is defined in number of days per year and is calculated for each of the 195 load cases and weighted based on probability. When counting LOLE events, only one event is counted per day even if an event occurs early in the day and then again later in the day. Across the industry, the traditional 1 day in 10 year LOLE standard is defined as 0.1 LOLE. Additional reliability metrics calculated are Loss of Load Hours (LOLH) in hours per year, and Expected Unserved Energy (EUE) in MWh.

Total system energy costs are defined as the following for each region:

$$Production\ Costs\ (Fuel\ Burn + Variable\ O\&M) + \ Purchase\ Costs - Sales\ Revenue \\ + Loss\ of\ Reserves + \ Cost\ of\ Unserved\ Energy$$

These components are calculated for each case and weighted based on probability to calculate total system energy costs for each scenario simulated. Loss of Reserves costs recognize the additional risk of depleting operating reserves and are costed out at the ORDC curve when they occur. As shown in the results these costs are almost negligible. The cost of unserved energy is simply the MWh of load shed multiplied by the value of lost load. System capacity costs are calculated separately outside of the SERVM model using the economic carrying cost of a new CT.

B. Reserve Margin Definition

For this study, winter and summer reserve margins are defined as the following:

- (Resources – Demand) / Demand
  - Demand is 50/50 peak forecast
  - Demand response programs are included as resources and not subtracted from demand
  - Solar capacity is counted at 1% capacity credit for winter reserve margin calculations, 37% for summer reserve margin calculations, and the small amount of battery capacity was counted at 80%.

As previously noted, the Base Case was simulated at different reserve margin levels by varying the amount of CT capacity in order to evaluate the impact of reserves on LOLE. In order to achieve lower reserve margin levels, capacity needed to be removed. For DEC, the Allen coal units were removed since they are scheduled to retire shortly after 2024 along with other CT capacity to achieve lower reserve margin levels. Table 11 shows a comparison of winter and summer reserve margin levels for the Base Case. As an example, when the winter reserve margin is 16%, the resulting summer reserve margin is 17.6% due to the 2,578 MW of solar on the system which provides greater summer capacity contribution.

Table 11. Relationship Between Winter and Summer Reserve Margin Levels

Winter	10.0%	12.0%	14.0%	16.0%	18.0%	20.0%
Corresponding Summer	12.4%	14.2%	15.9%	17.6%	19.4%	21.1%

V. Physical Reliability Results

Table 12 shows LOLE by month across a range of reserve margin levels for the Island Case. The analysis shows all of the LOLE falls in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in the Island scenario, a 22.5% winter reserve margin is required. This 22.5% reserve margin is required to cover the combined risks seen in load uncertainty, weather uncertainty, and generator performance for the DEC system. Given the significant solar on the system, the summer reserves are approximately 2% greater than winter reserves which results in essentially no reliability risk in the summer months when total LOLE is 0.1 days per year.

Table 12. Island Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
10.0%	12.4%	0.81	0.14	0.08	-	0.00	0.12	0.70	0.80	0.31	0.11	0.02	0.27	2.05	1.31	3.36
11.0%	13.3%	0.69	0.12	0.06	-	0.00	0.09	0.48	0.51	0.19	0.07	0.01	0.20	1.35	1.09	2.44
12.0%	14.2%	0.58	0.10	0.05	-	0.00	0.06	0.31	0.33	0.12	0.04	0.01	0.15	0.87	0.88	1.75
13.0%	15.0%	0.48	0.08	0.04	-	0.00	0.04	0.19	0.21	0.07	0.03	0.00	0.11	0.55	0.71	1.26
14.0%	15.9%	0.40	0.07	0.03	-	0.00	0.02	0.11	0.14	0.04	0.02	0.00	0.08	0.34	0.58	0.92
15.0%	16.8%	0.33	0.06	0.03	-	-	0.02	0.07	0.09	0.03	0.01	-	0.06	0.21	0.47	0.68
16.0%	17.6%	0.28	0.05	0.02	-	-	0.01	0.04	0.05	0.02	0.01	-	0.04	0.13	0.39	0.52
17.0%	18.5%	0.23	0.04	0.02	-	-	0.01	0.03	0.03	0.01	0.00	-	0.03	0.09	0.32	0.41
18.0%	19.4%	0.19	0.03	0.01	-	-	0.01	0.02	0.02	0.01	0.00	-	0.03	0.06	0.27	0.33
19.0%	20.2%	0.16	0.03	0.01	-	-	0.01	0.02	0.01	0.00	-	-	0.02	0.04	0.22	0.26
20.0%	21.1%	0.13	0.02	0.01	-	-	0.00	0.01	0.01	0.00	-	-	0.02	0.02	0.18	0.20
21.0%	22.0%	0.11	0.02	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.14	0.15
22.0%	22.8%	0.08	0.01	0.00	-	-	0.00	0.00	0.01	0.00	-	-	0.01	0.01	0.10	0.11
23.0%	23.7%	0.06	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.08	0.08
24.0%	24.6%	0.05	0.01	0.00	-	-	0.00	0.00	0.00	0.00	-	-	0.00	0.00	0.06	0.06

Table 13 shows LOLE by month across a range of reserve margin levels for the Base Case which assumes neighbor assistance. As in the Island scenario, all of the LOLE occurs in the winter when total LOLE is at 0.1 days per year showing the same increased risk in the winter. To achieve reliability equivalent to the 1 day in 10 year standard (0.1 LOLE) in this scenario that includes market assistance, a 16.00% winter reserve margin is required.

Table 13. Base Case Physical Reliability Results

Winter Reserve Margin	Summer Reserve Margin	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Summer LOLE	Winter LOLE	Total LOLE
5.00%	8.11%	0.21	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.05	0.33	0.38
6.00%	8.97%	0.20	0.05	0.02	0.00	0.00	0.00	0.02	0.02	0.00	0.00	0.00	0.04	0.04	0.30	0.35
7.00%	9.84%	0.18	0.05	0.02	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.04	0.28	0.31
8.00%	10.71%	0.17	0.04	0.01	0.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.03	0.03	0.25	0.28
9.00%	11.57%	0.15	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.03	0.03	0.23	0.25
10.00%	12.44%	0.14	0.04	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.21	0.23
11.00%	13.31%	0.13	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.02	0.02	0.18	0.20
12.00%	14.18%	0.11	0.03	0.01	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.01	0.01	0.16	0.18
13.00%	15.04%	0.10	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.15	0.15
14.00%	15.91%	0.09	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.13	0.13
15.00%	16.78%	0.08	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.11	0.12
16.00%	17.64%	0.07	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.10	0.10
17.00%	18.51%	0.06	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.08
18.00%	19.38%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.07	0.07
19.00%	20.24%	0.05	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.06	0.06
20.00%	21.11%	0.04	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.05	0.05
21.00%	21.98%	0.03	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.04	0.04
22.00%	22.84%	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.03	0.03

Table 14 shows LOLE and other physical reliability metrics by reserve margin for the Base Case simulations. Loss of Load Hours (LOLH) is expressed in hours per year and Expected Unserved Energy (EUE) is expressed in MWh. The table shows that an 8% reserve margin results in an LOLH of 0.69 hours per year. Thus, to achieve 2.4 hours per year, which is far less stringent than the 1 day in 10 year standard (1 event in 10 years), DEC would require a reserve margin less than 8%. Astrapé does not recommend targeting a standard that allows for 2.4 hours of firm load shed every year as essentially would expect a firm load shed during peak periods ever year. The hours per event can be calculated by dividing LOLH by LOLE. The firm load shed events last approximately 2-3 hours on average. As these reserve margins decrease and firm load shed events increase, it is expected that reliance on external assistance, depletion of contingency reserves, and more demand response calls will occur and increase the overall reliability risk on the system.

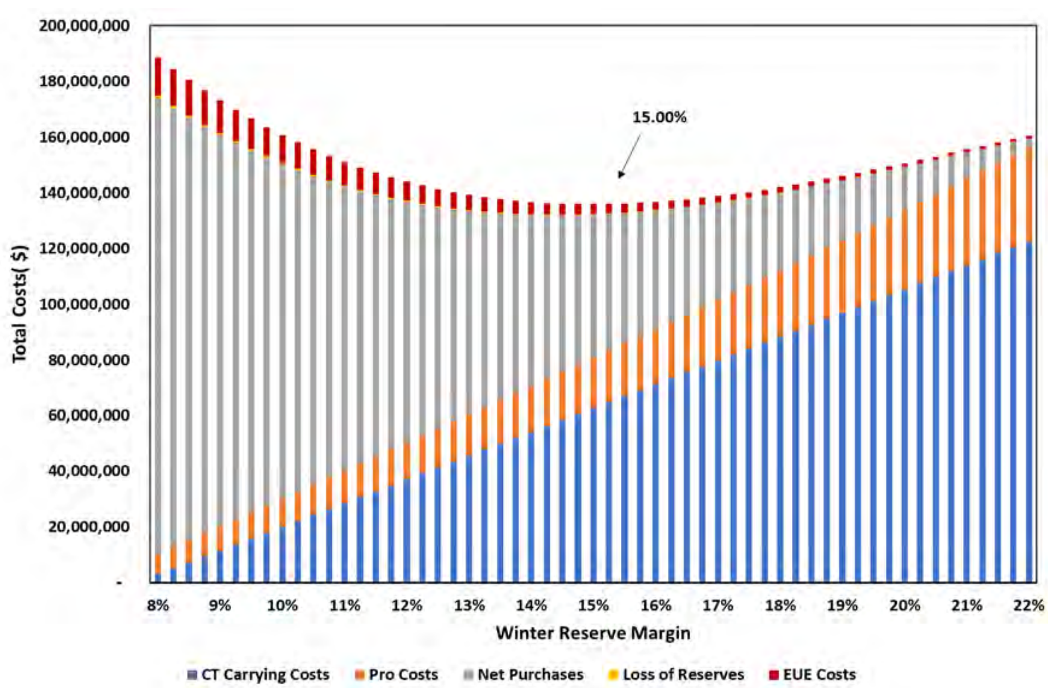
Table 14. Reliability Metrics: Base Case

Reserve Margin	LOLE	LOLH	EUE
%	Days Per Year	Hours Per Year	MWh
8.00%	0.28	0.69	748
8.50%	0.27	0.65	698
9.00%	0.25	0.61	650
9.50%	0.24	0.57	603
10.00%	0.23	0.54	559
10.50%	0.21	0.50	516
11.00%	0.20	0.47	475
11.50%	0.19	0.44	436
12.00%	0.18	0.41	399
12.50%	0.17	0.38	364
13.00%	0.16	0.35	330
13.50%	0.15	0.32	298
14.00%	0.14	0.29	268
14.50%	0.13	0.27	240
15.00%	0.12	0.25	214
15.50%	0.11	0.22	189
16.00%	0.10	0.20	167
16.50%	0.09	0.18	146
17.00%	0.08	0.17	127
17.50%	0.08	0.15	110
18.00%	0.07	0.13	94
18.50%	0.06	0.12	81
19.00%	0.06	0.11	69
19.50%	0.05	0.10	59
20.00%	0.05	0.09	51
20.50%	0.04	0.08	45
21.00%	0.04	0.07	40
21.50%	0.04	0.06	38
22.00%	0.03	0.06	37
22.50%	0.03	0.06	38
23.00%	0.03	0.05	41
23.50%	0.03	0.05	46
24.00%	0.02	0.05	52

VI. Base Case Economic Results

While Astrapé believes physical reliability metrics should be used for determining planning reserve margin because customers expect to have power during extreme weather conditions, customer costs provide additional information in resource adequacy studies. From a customer cost perspective, total system costs were analyzed across reserve margin levels for the Base Case. Figure 11 shows the risk neutral costs at the various winter reserve margin levels. This risk neutral represents the weighted average results of all weather years, load forecast uncertainty, and unit performance iterations at each reserve margin level and represents the expected value on a year in and year out basis.

Figure 11. Base Case Risk Neutral Economic Results[27]

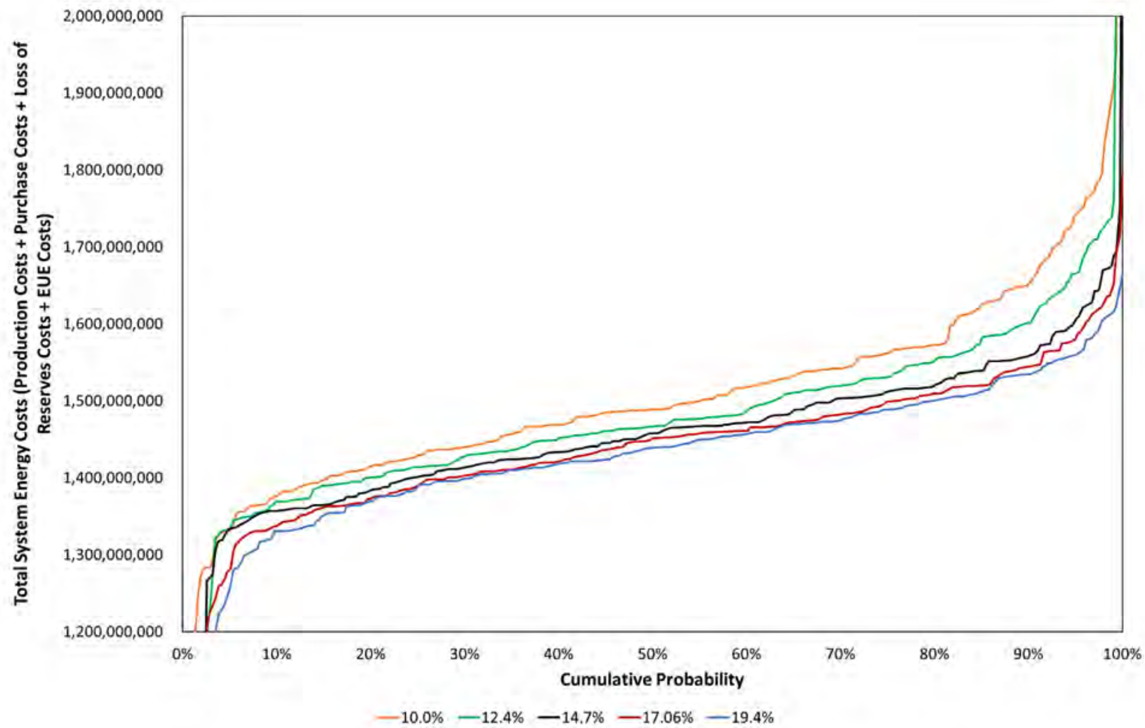


[27] Costs that are included in every reserve margin level have been removed so the reader can see the incremental impact of each category of costs. DEC has approximately 1.5 billion dollars in total costs.

As Figure 11 shows, the lowest risk neutral cost falls at a 15.00% reserve margin very close to the one day in 10-year standard (LOLE of 0.1). These values are close because the summer reserve margins are only slightly higher than the winter reserve margins which increases the savings of adding additional CT capacity. The majority of the savings seen in adding additional capacity is recognized in the winter.[28] The cost curve is fairly flat for a large portion of the reserve margin curve because when CT capacity is added there is always system energy cost savings from either reduction in loss of load events, savings in purchases, or savings in production costs. This risk neutral scenario represents the weighted average of all scenarios but does not illustrate the impact of high-risk scenarios that could cause customer rates to be volatile from year to year. Figure 12, however, shows the distribution of system energy costs (production costs, purchase costs, loss of reserves costs, and the costs of EUE) at different reserve margin levels. This figure excludes fixed CT costs which increase with reserve margin level. As reserves are added, system energy costs decline. By moving from lower reserve margins to higher reserve margins, the volatile right side of the curve (greater than 85% Cumulative Probability) is dampened, shielding customers from extreme scenarios for relatively small increases in annual expected costs. By paying for additional CT capacity, extreme scenarios are mitigated.

[28] As the DEC study shows, the lower DEC summer reserve margins increase the risk neutral economic reserve margin level compared to the DEP Study.

Figure 12. Cumulative Probability Curves



The next table shows the same data laid out in tabular format. It includes the weighted average results as shown in Figure 11 as well as the energy savings at higher cumulative probability levels. As shown in the table, going from the risk neutral reserve margin of 15% to 17% increases customer costs on average by $2.9 million a year[29] and reduces LOLE from 0.12 to 0.08 events per year. The LOLE for the island scenario decreases from 0.68 days per year to 0.41 days per year. However, 10% of the time energy savings are greater than or equal to $21 million if a 17% reserve margin is maintained versus the 15% reserve margin. And 5 % of the time, $34 million or more is saved.

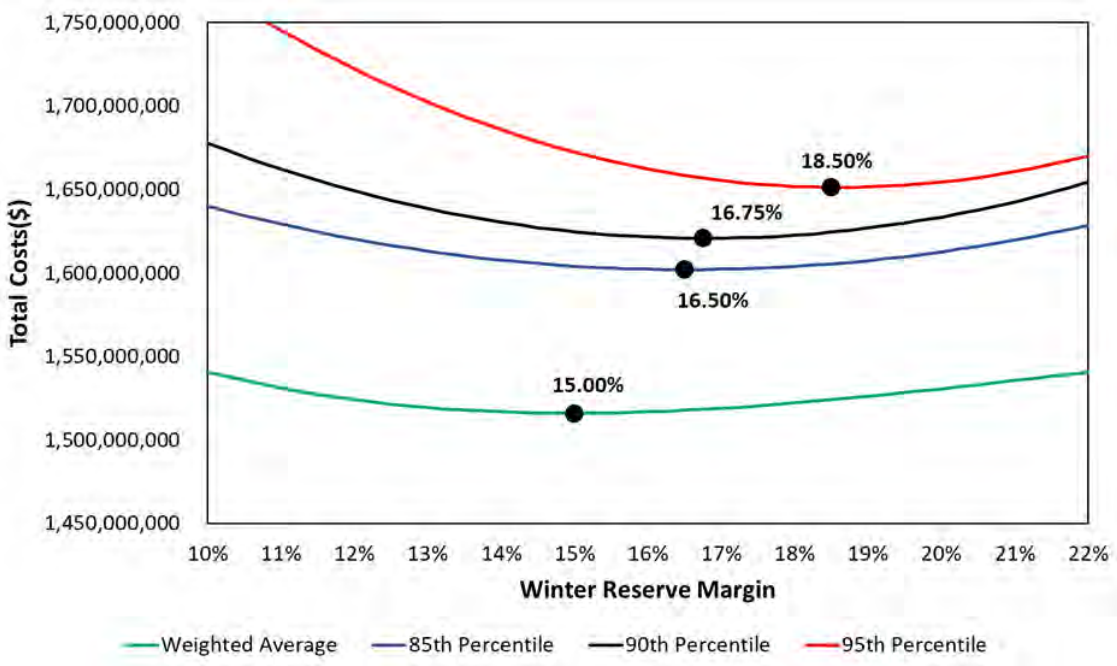
[29] This includes $17 million for CT costs and $14 million of system energy savings.

Table 15. Annual Customer Costs vs LOLE

Reserve Margin	Change in Capital Costs ($M)	Change in Energy Costs ($M)	Total Weighted Average Costs ($M)	85th Percentile Change in Energy Costs ($M)	90th Percentile Change in Energy Costs ($M)	95th Percentile Change in Energy Costs ($M)	LOLE (Days Per Year)	LOLE (Days Per Year) Island Sensitivity
15.00%	-	-	-	-	-	-	0.12	0.68
16.00%	8.5	-7.8	0.8	-10.0	-11.7	-18.6	0.1	0.52
17.00%	17.1	-14.2	2.9	-19.0	-21.0	-34.0	0.08	0.41
18.00%	25.6	-19.5	6.1	-25.8	-27.8	-46.1	0.07	0.33
19.00%	34.2	-24.0	10.1	-30.8	-32.1	-55.0	0.06	0.26
20.00%	42.7	-28.0	14.7	-34.1	-33.9	-60.6	0.05	0.20

The next figure takes the 85^{th}, 90^{th}, and 95^{th} percentile points of the total system energy costs in Figure 12 and adds them to the fixed CT costs at each reserve margin level. It is rational to view the data this way because CT costs are more known with a small band of uncertainty while the system energy costs are volatile as shown in the previous figure. In order to attempt to put the fixed costs and the system energy costs on a similar basis in regards to uncertainty, higher cumulative probability points using the 85^{th} – 95^{th} percentile range can be considered for the system energy costs. While the risk neutral lowest cost curve falls at 15% reserve margin, the 85^{th} to 95^{th} percentile cost curves point to a 16-19% reserve margin.

Figure 13. Total System Costs by Reserve Margin



Carrying additional capacity above the risk neutral reserve margin level to reduce the frequency of firm load shed events in DEC is similar to the way PJM incorporates its capacity market to maintain the one day in 10-year standard (LOLE of 0.1). In order to maintain reserve margins that meet the one day in 10-year standard (LOLE of 0.1), PJM supplies additional revenues to generators through its capacity market. These additional generator revenues are paid by customers who in turn see enhanced system reliability and lower energy costs. At much lower reserve margin levels, generators can recover fixed costs in the market due to capacity shortages and more frequent high prices seen during these periods, but the one day in 10-year standard (LOLE of 0.1) target is not satisfied.

VII. Sensitivities

Several sensitivities were simulated in order to understand the effects of different assumptions on the 0.1 LOLE minimum winter reserve margin and to address questions and requests from stakeholders.

Outage Sensitivities

As previously noted, the Base Case included a total of 400 MW of cold weather outages between DEC and DEP below ten degrees Fahrenheit based on outage data for the period 2016-2019. Sensitivities were run to see the effect of two cold weather outage assumptions. The first assumed that the 400 MW of total outages between DEC and DEP below ten degrees Fahrenheit were removed. As Table 16 indicates, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is lowered by 1.25% from the Base Case to 14.75%. This shows that if the Company was able to eliminate all cold weather outage risk, it could carry up to a 1.25% lower reserve margin. However, Astrapé recognizes based on North American Electric Reliability Corporation (NERC) documentation across the industry[30] that outages during cold temperatures could be substantially more than the 400 MW being applied at less than 10 degrees in this modeling.

30 https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdfvv (page 5)

https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf

(beginning page 43)

Table 16. No Cold Weather Outage Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
No Cold Weather Outages	14.75%	14.75%	16.75%

The second outage sensitivity showed what the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) would need to be if cold weather outages were based solely on 2014-2019 historical data which increased the total MW of outages from 400 MW to 800 MW. Table 17 shows that the minimum reserve margin for 0.1 LOLE is 17.25 %.

Table 17. Cold Weather Outages Based on 2014-2019 Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Cold Weather Outages Based on 2014 - 2019	17.25%	15.00%	17.00%

Load Forecast Error Sensitivities

These sensitivities were run to see the effects of the Load Forecast Error (LFE) assumptions. In response to stakeholder feedback, an asymmetric LFE distribution was adopted in the Base Case which reflected a higher probability weighting on over-forecasting scenarios. In the first sensitivity, the LFE uncertainty was completely removed. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 0.25% to 16.25%. This demonstrates that the load forecast error assumed in the Base Case was reducing the target reserve margin levels since over-forecasting was more heavily weighted in the LFE distribution. Because of this result, Astrapé did not simulate additional sensitivities such as 2-year, 3-year, or 5-year LFE distributions.

Table 18. Remove LFE Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Remove LFE	16.25%	15.00%	16.00%

The second sensitivity removed the asymmetric Base Case distribution and replaced it with the originally proposed normal distribution. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) increased by 1.0% to 17.0%.

Table 19. Originally Proposed LFE Distribution Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Originally Proposed Normal Distribution	17.00%	16.00%	18.00%

Solar Sensitivities

The Base Case for DEC assumed that there was 2,578 MW of solar on the system. The first solar sensitivity decreased this number to 1,626 MW. This change in solar had no impact on the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) as the results in Table 20 show because the capacity contribution of solar in the winter reserve margin calculation is 1%.

Table 20. Low Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Low Solar	16.00%	16.00%	18.25%

The second solar sensitivity increased the amount of solar on the DEC system to 3,752 MW. This increase also had very little impact on the minimum reserve margins as Table 21 indicates. Both of these results are expected as solar provides almost no capacity value in the winter.

Table 21. High Solar Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
High Solar	15.75%	14.00%	14.50%

Demand Response (DR) Sensitivity

In this scenario, the winter demand response is increased to 1,122 MW to match the summer capacity. It is important to note that DR is counted as a resource in the reserve margin calculation similar to a conventional generator. Simply increasing DR to 1,122 MW results in a higher reserve margin and lower LOLE compared to the Base Case. Thus, CT capacity was adjusted (lowered) in the high DR sensitivity to maintain the same reserve margin level. Results showed that the 0.1 LOLE minimum reserve margin actually increased from 16.00% to 16.75% due to demand response's dispatch limits compared to a fully dispatchable traditional resource. DR may be an economic alternative to installing CT capacity, depending on market potential and cost. However, it should be noted that while Duke counts DR and conventional capacity as equivalent in load carrying capability in its IRP planning, the sensitivity results show that DR may have a slightly lower equivalent load carrying capability especially for programs with strict operational limits. The results are listed in Table 22 below.

Table 22. Demand Response Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Demand Response Winter as High as Summer	16.75%	18.25%	19.50%

No Coal Sensitivity

In this scenario, all coal units were replaced with CC/CT units. The CC units were modeled with a 4% EFOR and the CT units were modeled with a 5% EFOR. Due to the high EFOR's of the DEC coal units, the minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) decreased slightly as shown in Table 23 below.

Table 23. No Coal Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Retire all Coal	15.25%	17.00%	20.25%

Climate Change Sensitivity

In this scenario, the loads were adjusted to reflect the temperature increase outlined in the National Oceanic and Atmospheric Administration (NOAA) Climate Change Analysis[31]. Based on NOAA's research, temperatures since 1981 have increased at an average rate of 0.32 degrees Fahrenheit per decade. Each synthetic load shape was increased to reflect the increase in temperature it would see to meet the 2024 Study Year. For example, 1980 has a 1.4 degree increase ($0.32 \frac{°F}{Decade} * \frac{1\ Decade}{10\ Year} * 44\ Years$). After the loads were adjusted, the analysis was rerun. The summer peaks saw an increase and the winter peaks especially in earlier weather years saw a decrease. The minimum reserve margin for the one day in 10-year standard (LOLE of 0.1) is reduced to 16.00% from 15.75% in the Base Case under these assumptions. The results are listed in the table below.

Table 24. Climate Change Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**Weighted Average (risk neutral)**	**90th %**
Base Case	16.00%	15.00%	16.75%
Climate Change	15.75%	14.25%	16.75%

[31] https://www.climate.gov/news-features/understanding-climate/climate-change-global-temperature

VIII. Economic Sensitivities

Table 25 shows the economic results if the cost of unserved energy is varied from $5,000/MWh to $25,000/MWh and the cost of incremental capacity is varied from $40/kW-yr to $60/kW-yr. As CT costs decrease, the economic reserve margin increases and as CT costs increase, the economic reserve margin decreases. The opposite occurs with the cost of EUE. The higher the cost of EUE, the higher the economic target.

Table 25. Economic Sensitivities

	Economics	
Sensitivity	**Weighted Average (risk neutral)**	**90th %**
Base Case	15.00%	16.75%
CT costs $40kW-yr	16.00%	17.25%
CT costs $60/kW-yr	13.75%	16.00%
EUE 5,000 $/MWh	14.50%	16.25%
EUE 25,000 $/MWh	15.25%	16.75%

IX. DEC/DEP Combined Sensitivity

A set of sensitivities was performed which assumed DEC, DEP-E, and DEP-W were dispatched together and all reserves were calculated as a single company across the three regions. In these scenarios, all resources down to the firm load shed point can be utilized to assist each other and there is a priority in assisting each other before assisting an outside neighbor. The following three scenarios were simulated for the Combined Case and their results are listed in the table below:

1) Combined-Base
2) Combined Target 1,500 MW Import Limit- This scenario assumed a maximum import limit from external regions into the sister utilities of 1,500 MW[32].
3) Combined-Remove LFE

As shown in the table below, the combined target scenario yielded a 0.1 LOLE reserve margin of 16.75% (based on DEC and DEP coincident peak).

Table 26. Combined Case Results

	LOLE	Economics	
Sensitivity	**1 in 10**	**weighted avg (risk neutral)**	**90th %**
Base Case	19.25%	10.25%	17.50%
Combined Target	16.75%	17.00%	17.75%
Combined Target 1,500 MW Import Limit	18.00%	17.25%	18.25%
Combined Target - Remove LFE	17.25%	17.00%	18.25%

[32] 1,500 MW represents approximately 4.7% of the total reserve margin requirement which is still less constrained than the PJM and MISO assumptions noted earlier.

X. Conclusions

Based on the physical reliability results of the Island, Base Case, Combined Case, additional sensitivities, as well as the results of the separate DEP Study, Astrapé recommends that DEC continue to maintain a minimum 17% reserve margin for IRP purposes. This reserve margin ensures reasonable reliability for customers. Astrapé recognizes that a standalone DEC utility would require a 22.5% reserve margin to meet the one day in 10-year standard (LOLE of 0.1) and even with market assistance, DEC would need to maintain a 16.00% reserve margin. However, given the combined DEC and DEP sensitivity resulting in a 16.75% reserve margin, and the 19.25% reserve margin required by DEP to meet the one day in 10-year standard (LOLE of 0.1), Astrapé believes the 17% reserve margin as a minimum target is still reasonable for planning purposes. Since the sensitivity results removing all economic load forecast uncertainty increases the reserve margin to meet the 1 day in 10-year standard, Astrapé believes this 17% minimum reserve margin should be used in the short- and long-term planning process.

To be clear, even with 17% reserves, this does not mean that DEC will never be forced to shed firm load during extreme conditions as DEC and its neighbors shift to reliance on intermittent and energy limited resources such as storage and demand response. DEC has had several events in the past few years where actual operating reserves were close to being exhausted even with higher than 17% planning reserve margins. If not for non-firm external assistance which this study considers, firm load would have been shed. In addition, it is not possible to capture all tail end risk that could occur from a reliability perspective. Astrapé's approach has been to model the system's risks around weather, load, generator performance, and market assistance as accurately as possible without overly conservative assumptions. Based on all results, Astrapé believes planning to a 17% reserve margin is prudent from a physical reliability perspective and for small increases in costs above the risk-neutral 15% reserve margin level, customers will experience enhanced reliability and less rate volatility.

As the DEC resource portfolio changes with the addition of more intermittent resources and energy limited resources, the 17% minimum reserve margin is sufficient as long as the Company has accounted for the capacity value of solar and battery resources which changes as a function of penetration. DEC should also monitor changes in the IRPs of neighboring utilities and the potential impact on market assistance. Unless DEC observes seasonal risk shifting back to summer, the 17% reserve margin should be reasonable but should be re-evaluated as appropriate in future IRPs and future reliability studies. To ensure summer reliability is maintained, Astrapé recommends not allowing the summer reserve margin to drop below 15%.[33]

[33] Currently, if a winter target is maintained at 17%, summer reserves will be above 15%.

XI. Appendix A

Table A.1 Base Case Assumptions and Sensitivities

Assumption	Base Case Value	Sensitivity	Comments
Weather Years	1980-2018		Based on the historical data, the 1980 - 2018 period aligns well with the last 100 years. Shorter time periods do not capture the distribution of extreme days seen in history.
Synthetic Loads and Load Shapes	As Documented in 2-21-20 Presentation	Impact of Climate Change on synthetic load shapes and peak load forecast	Note: This is a rather complex sensitivity and the ability to capture the impact of climate change may be difficult. We would appreciate input and suggestions from other parties on developing an approach to capture the potential impacts of climate change on resource adequacy planning.
LFE	Use an asymmetrical distribution. Use full LFE impact in years 4 and beyond. Recognize reduced LFE impacts in years 1-3.	1,2,3,5 year ahead forecast error	
Unit Outages	As Documented in 2-21-20 Presentation		
Cold Weather Outages	Moderate Cold Weather Outages: Capture Incremental Outages at temps less than 10 degrees based on the 2016 - 2018 dataset (~400 MW total across the DEC and DEP for all temperature below 10 degree. This will be applied on a peak load ratio basis) For Neighboring regions, the same ratio of cold weather outages to peak load will be applied.	2 Sensitivities: (1) Remove cold weather outages (2) Include cold weather outages based on 2014 -2018 dataset	The DEC and DEP historical data shows that during extreme cold temperatures it is likely to experience an increase in generator forced outages; this is consistent with NERC's research across the industry. https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC%20WRA%202019_2020.pdf - page 5 https://www.nerc.com/pa/rrm/ea/Documents/South_Central_Cold_Weather_Event_FERC-NERC-Report_20190718.pdf - beginning on pg 43
Hydro/Pumped Storage	As Documented in 2-21-20 Presentation		
Solar	As Documented in 2-21-20 Presentation		
Demand Response	As Documented in 2-21-20 Presentation	Sensitivity increasing winter DR	
Neighbor Assistance	As Documented in 2-21-20 Presentation	Island Sensitivity	Provide summary of market assistance during EUE hours; transmission versus capacity limited.
Operating Reserves	As Documented in 2-21-20 Presentation		
CT costs/ORDC/VOLL	As Documented in 2-21-20 Presentation	Low and High Sensitivities for each	
Study Topology	Determine separate DEC and DEP reserve margin targets	Combined DEC/DEP target	A simulation will be performed which assumes DEC, DEP-E and DEP-W are dispatched together and reserves are calculated as a single company across the three regions.

XII. Appendix B

Table B.1 Percentage of Loss of Load by Month and Hour of Day for the Base Case

	Month											
Hour of Day	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	0.16%	0.16%	-	-	-	-	-	-	-	-	-	-
5	0.98%	0.49%	-	-	-	-	-	-	-	-	-	-
6	4.43%	1.48%	-	-	-	-	-	-	-	-	-	-
7	16.56%	5.74%	-	-	-	-	-	-	-	-	-	0.33%
8	32.79%	7.87%	-	-	-	-	-	-	-	-	-	2.62%
9	15.57%	0.82%	-	-	-	-	-	-	-	-	-	0.16%
10	4.43%	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	0.16%	-	-	-	-
18	-	-	-	-	-	-	0.33%	0.98%	-	-	-	-
19	-	-	-	-	-	-	0.49%	1.15%	-	-	-	-
20	-	-	-	-	-	-	0.16%	0.33%	-	-	-	-
21	-	-	-	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-
Sum	74.92%	16.56%	1.80%	-	-	-	0.98%	2.62%	-	-	-	3.11%

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Duke Energy Carolinas, LLC's
and
Duke Energy Progress, LLC's
Response to
SC Office of Regulatory Staff
Data Request No. 2-5

Docket No. 2021-89-E
Docket No. 2021-90-E

Date of Request: **May 21, 2021**
Date of Response: **June 1, 2021**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to SC Office of Regulatory Staff, was provided to me by the following individual(s): Tom Davis, Principal Planning Analyst, and was provided to the SC Office of Regulatory Staff under my supervision.

Rebecca J. Dulin
Associate General Counsel
Duke Energy Carolinas, LLC and
Duke Energy Progress, LLC

SC Office of Regulatory Staff
First Request for Production & Info
DEC and DEP 2021 Avoided Cost
Docket Nos. 2021-89-E & 2021-90-E
Item No.2-5
Page 2 of 3

DUKE ENERGY CAROLINAS, LLC and DUKE ENERGY PROGRESS, LLC

Request:

2-5 A comparison of the Loss of Load Risk from the 2020 Reliability Assessment study and the 2018 Value of Solar Capacity Study conducted by Astrape (Tranche 2) shows a substantial difference in the LOLE distributions, especially in the evenings. Please describe the major differences in the study assumptions and/or methods that drive the changes in distributions. Also, please discuss whether the 2018 or the 2020 study assumption and/or method is more representative of what is expected for 2022.

Response:

The major driver for the difference in the winter day LOLE distribution is likely the result of enhancements made in the load modeling in the 2020 Resource Adequacy (RA) Study as described more fully below. However, it is noted that all other data was updated in the 2020 RA Study including resource characteristics, generator outage rates, solar penetration, hourly solar profiles representing more sites across the jurisdictions, as well as neighbor resources, load, and transmission capability. Also, the higher solar penetration assumptions included in the 2020 RA Study would shift more LOLE to the winter (below are the differences in solar penetration between the two studies). All of these changes could have some impact on the LOLE seen in the cases.

DEC included 2,300 MW of solar in the 2018 Study vs 2,578 MW in the 2020 RA study

DEP included 3,290 MW of solar in the 2018 Study vs 4,107 MW in the 2020 RA Study

The loads in the 2018 Solar Capacity Value Study were based on the 2016 RA Study load modeling. For extreme cold weather days in the 2016 RA Study, the morning peak hour was changed with the cold weather regression equations and the rest of the day was shaped to an average winter day. For the 2020 RA Study, this methodology was updated and separate regression equations were used for the morning and evening peaks which provided a better representation of the morning and evening peak load relationship.

In the 2020 RA Study, the evening peaks were reduced based on the more detailed regression analysis and provide a more accurate representation of a winter peak day. Thus, the evening peak was likely somewhat overstated in the 2018 Solar Capacity Value Study (2016 RA study) since it was based on the average winter daily shape load modeling. The attached file "ORS AIR 2-5_Load Modeling.xlsx" shows that the 2020 RA Study load modeling more closely matches an actual extreme winter peak day compared to the 2016 load modeling. It is also noted that the change in load modeling only changed the distribution of hours that firm load shed occurred and likely had little to no impact on total LOLE since LOLE is represented as any day with firm load shed whether it is 1 hour or 10 hours. Finally, it is noted that the 2020 RA Study is expected to be more representative of the expected LOLE in 2022 based on the updates made to the load modeling. Also reference response to ORS AIR 1-4b.

ORS AIR 2-5_Load Modeling.xlsx